Valuing Expanded Wind Generation and Geographic Diversity in the Rocky Mountain West

Preliminary Results

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ABSTRACT

Increasing integration of wind generation in the United States provides several opportunities and challenges to policy-makers. Even without subsidy, wind is now the cheapest form of new generation in many areas of the country, and costs continue to decline. In addition to cost reduction, expansion of wind generation also reduces emissions from existing fossil-fueled generation infrastructure, improving regional health outcomes, particularly when it results in reduced fossil-fueled generation in urban areas, and reduced greenhouse gas emissions. Such expansion of wind also creates challenges. In the existing transmission system, rising wind generation in the United States poses a challenge to system operators due to wind intermittence and a current lack of economic storage alternatives. Geographic diversification of wind generation facilities, however, can minimize the system impact of site-specific intermittence; but the location of wind resources can exacerbate problems of congestion on a transmission-constrained grid, with often unanticipated impacts to generation, cost and emission outcomes. To optimize the potential benefits from greater expansion of wind generation, spatial distribution of wind resources on market price outcomes and emission reductions should be considered, subject to the constraints posed by existing transmission capacity. This paper attempts to determine the impacts of wind expansion using a simulation of the Rocky Mountain Power Area in the western United States. To quantify the potential benefit-cost tradeoffs from cost improvements and emissions reductions while considering potential congestion impacts to system costs and emissions outcomes, the results report impacts of varying geographic diversity of wind resources while accounting for potential transmission congestion and time-of-day price variation, using a dispatch model of the Rocky Mountain Power Area region to simulate generation outcomes. Preliminary results indicate that, in the absence of transmission constraints, greater geographic diversification of additional wind power results in a win-win situation with minimal renewable generation variance, low electricity market prices, and greater reduction of total emissions. On a transmission-constrained grid, however, demand and supply conditions within specific sub-regions of the grid dictate the optimality of alternative wind generation siting choices. In each hour that transmission congestion occurs, costs and benefits of wind site placement are asymmetric across the system. Such results are important to system planners as they demonstrate that in the presence of congestion the benefits

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renewable generation may provide may be reinforced or mitigated depending on specific congestion conditions across a regional electricity grid and therefore create tradeoffs across a regional grid.

1. Introduction

Wind power in the United States has been growing rapidly since the 2000s and is the largest source of new renewable electricity generation (American Wind Energy Association, 2017). The increase in wind development across the United States over the past decade reflects a combination of improved wind turbine technology, increased access to transmission capacity, the state-level RPS and federal production tax credits and grants. Today, twenty-nine states plus the District of Columbia have adopted a Renewable Portfolio Standards (RPS) to require that a minimum share of electrical generation is produced by renewable resources[5]. According to the EIA, in 2017 monthly renewable electricity generation surpassed nuclear for the first time since 1984. Wind turbines provided 8% of United States generating capacity as of 2016, more than any other renewable source. The private and social benefits from wind can be significant. Even without subsidies, wind generation is often the cheapest form of electricity generation in places with adequate wind resources. Electricity generation is also a significant source of carbon dioxide emissions, producing 34% of total energy related CO2 emissions in 2017, with coal-fired power plants accounting for 69% of this total.[6] Expanded wind generation can displace traditional fuel sources, providing both lower-cost electricity and fewer emissions that are harmful to human health and the environment.

What differentiates renewable generation from conventional sources of electricity is the variability and intermittency of renewable energy resources, that they have near-zero marginal operational costs, and that renewable generation has a limited capacity value relative to its rated capacity (Flores-Espino et al., 2016). Though wind makes up about 8% of the total U.S. electricity generation capacity, wind generators only provided about 5% of total U.S. electricity generation in 2016, according to the EIA, because wind turbines have relatively low capacity factors. Capacity factors, which measure actual output over a certain period as a percent of the total mechanical ability of the turbine to generate sufficient wind, average between about 25% and 40% for wind generators and vary based on seasonal patterns and geographic locations.

The expansion and integration of wind power provide a unique set of challenges to electricity network planners and regulators. Policy-makers want to maintain power supply to meet demand at low cost and ensure system reliability. Without efficient storage technology and the unpredictability of wind, scheduling electricity with variable generation incurs both "balancing costs", costs of integration of wind into the electricity system, and "backup costs", costs associated with maintaining system reliability (Roques et al., 2010). Balancing costs are associated with the short-term fluctuations and the lack of predictability of wind power including keeping back-up generation

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[5] As of 2017, according to the National Conference of State Legislatures. Three U.S. territories have also adopted an RPS, while eight states and one territory have at least set (voluntary) renewable energy goals (Jocelyn Durkay, 2017).

[6] See EIA, 2018 "Energy and the environment Explained: where Greenhouse Gases Come From" https://www.eia.gov/energyexplained/index.php?page=environment_where_ghg_come_from

available to replace wind resources when they are unavailable, electricity storage, and/or additional transmission capacity to supply replacement generation if needed. Backup costs are incurred in times of peak demand if wind power cannot meet these needs and are exacerbated by the variability of wind power during these times (Gross et al., 2006). Power systems have been designed to handle the variable nature of loads, but the additional supply-side variability and uncertainty introduced by renewable generation poses new challenges for utilities and system operators.

Variability in generation sources can require additional actions to balance the system and maintain short- term grid reliability. Greater flexibility is needed in the system to accommodate supply-side variability and the relationship to generation levels and loads. Electricity is dispatched from generators with lowest to highest marginal cost whenever possible to minimize system electricity cost, and because renewable sources use no fuel and have near-zero marginal costs, electricity from these sources is used first when available. If for example, wind generation decreases when load level increases, additional actions are taken to balance the system. System operators need to ensure that they have sufficient other resources to handle significant up or down ramps in wind generation. Another challenge occurs when wind (or solar) generation is available during low load levels; in some cases, conventional generators may need to turn down their minimum generation levels. There are periods when the net load changes, or ramps, more quickly than the load alone.[7]

Figure 1 provides an example of the flexibility necessary to accommodate a high penetration of wind energy. Using all the wind power that is generated still requires conventional generators to meet the remaining net load. In the figure, load and net load are plotted for a sample week, and we can see that there are periods when the net load changes, or ramps, more quickly than the load alone caused by the fluctuations in wind generation and requires conventional generators like coal-fired power plants to "load follow". Such generators, once referred to as "baseload generators" were originally designed to run at constant rates and high capacity factors, but now must vary their output to follow lower-cost intermittent wind and solar resources. Lower "turndown" periods are generally at night, when there is more wind generation, resulting in remaining generators operating at a lower output level. Operating conventional fossil-fueled resources on a more flexible schedule can often increase their operating costs when compared to outcomes when only conventional resources are used to generate electricity. This is especially true of coal-fired power plants, which were not originally designed follow the variations in net load caused by increased renewable energy integration. The resulting lower capacity factors at these plants has resulted in lower profitability and contributed to the large number of coal-fired power plant retirements observed over the last decade.

The required cycling of fossil-fueled generators can also cause the profitability of conventional power plants to decline for other reasons. Such operational patterns increase the wear-and-tear on generating units and decrease their efficiency, due to thermal stresses on equipment because of changes in output. This is especially true of coal-fired power plants. The Western Wind and Solar

[7] Net load is defined as total load (demand) minus variable (renewable) generation (Flores-Espino et al., 2016).

Integration Study Phase 2 (WWSIS-2) conducted by the NREL found that high penetrations of wind- and solar- induced cycling costs \$35 million a year to \$157 million a year across the West, while displacing fuel costs saved approximately \$7 billion (Lew et al., 2013). Cycling can also impact emissions from fossil-fueled generators because plants are run at part loads, ramped, and started more frequently. Although wind displaces substantial emissions by reducing fossil-fuel use for electricity generation, the emissions impacts on conventional generating sources due to the required cycling necessary to load-follow renewable resources has caused some industry observers to question the overall emissions benefit of renewable energy sources. Cycling of plants can lead to increases or decreases in emissions of carbon dioxide, nitrogen oxides, and sulfur dioxides from fossil-fueled generators, depending on the plant type and wind/solar power mix. The WWSIS-2 study found that cycling had a negligible impact on expected CO2 emission reductions, improved NOx emissions reductions by approximately 1% to 2% and worsened SO2 emissions reductions by approximately 2% to 5%.

Greater system flexibility can allow for greater integration of renewable energy, for example, fast automated demand-response resources and storage systems (Flores-Espino et al., 2016). The time scale at which resources and dispatch are scheduled, however, often reduces the usefulness of these tools to manage variability. Awerbuch (2004) argues that energy planning should focus more on developing optimal generation portfolios to balance specific objectives. Geographic diversification of wind resources, for instance using resources that are at different locations, provides an opportunity to take advantage of the characteristics of spatially differing wind patterns, to develop a more stable and reliable system, while still taking advantage of a relatively low-cost generation source. Geographic diversification of wind power can help smooth out unpredictable fluctuations in wind power generation reducing the costs and concerns to maintaining grid reliability. However, the location of wind resources requires transmission capacity to deliver power to market when it is available. The coordination of wind generation to total demand on a fixed transmission system can be difficult, and is further exacerbated by the intermittency of wind, and results in problems of congestion (see Godby et al., 2014). Choosing a diverse allocation of wind resources may help to reduce the issues caused by the nature of wind itself, but both market and non-market outcomes may be distorted by lacking transmission capacity.

Geographic diversity can be defined as diversity that arises from using two resources from different locations (Naughton et al., 2013). Previous empirical studies have shown that as the distance between wind farms widens, wind speed correlations between those wind farms fall (Milligan and Artig, 1998; Drake and Hubacek, 2007; Roques et al., 2010). In the Western Wind and Solar Integration Study Phase 2 (Lew et al., 2013) the authors find that aggregating output from many photovoltaic (PV) plants smooths out the variability, particularly when solar projects are spread out geographically. Wind diversity can lead to less volatile changes in aggregate energy output. At a given location, the variability of the wind arises from several sources including diurnal and seasonal variations. Thus, using energy produced from several different sites can potentially help to smooth out variations that occur at single sites, as these time-dependent features will not happen at the same time at all sites. One trend noted in recent years is the increasing size of wind generation facilities.[8] As single-site wind farms grow, more wind generation will be clustered in individual locations. If the potential benefits of spatial diversification are significant, it may be better that developers not continue building larger single-site wind farms and instead consider spreading our turbines and sites across a wider region. Optimal wind power deployment may need to consider regional variation in wind power resources and the decreasing correlation between farms' output as the distance between these farms increases.

Wind energy resources are often located in remote areas far away from demand centers. Long distance transmission capability is required to deliver large amounts of power across the country. Wide-scale integration of wind has been hampered by a lack of transmission capacity to many parts of the rocky Mountain west (see for example Godby et al, 2014). This problem has been in part exacerbated by the historically low investment in transmission. From 1988 – 1998, national electricity demand grew by 30%, while transmission grew by only 15%; from 1999 – 2009 demand grew by 20% and transmission by only 3% (Crabtree and Misewich, 2010). Reasons for limited transmission expansion vary - from the high cost of cost of securing rights of way to building transmission. In the western United States especially, this can be complicated by the large areas of federal public lands that require significant and slow environmental permitting not present on private lands. Building transmission is also difficult due to permitting time lags and uncertainty regarding future electricity demand. Long transmission links can take a decade to permit and developers investing in such costly projects are uncertainty whether future demand conditions anticipated a decade before will become a reality once the transmission links are built. In some areas there are also community concerns about new right-of-way above ground transmission towers; "not in my backyard" arguments are costly to overcome and can delay or stop above-ground transmission construction. While geographic diversity implies a combined use of spatially spread out wind turbines, a lack of adequate transmission capacity may prohibit it.

Lack of new transmission may not only prohibit building of wind sites that can fully take advantage of spatial differences in wind resources, it can also limit the use of wind sites on existing transmission systems as transmission lines become congested. Power will flow over the transmission line from the low-cost location to the high cost location at times when demand spikes or there is an unexpected increase in renewable generation. If a transmission line has a limit below that needed to allow the use of low cost generation in other places to be imported, the low-cost generation plant could be "constrained off" (Hogan, 1998). This occurs to maintain system stability. In these periods congestion occurs and demand is met by higher cost plants that in an unconstrained case would not have been operating, raising system costs and reducing the benefit adding spatially diverse wind sites to the power grid. The transmission congestion causes the marginal cost to differ in the two

[8] For example, in 2017, four of the five largest wind farms in the United states ranged in size from just over 700 MW to 900 MW, while the largest had a capacity of 1547 MW. In the last five years, however, several proposals for new wind facilities in have planned facilities over 2000 to 3000 MW in size, twice the size of the largest current wind farms and ten to twenty times the size of typical wind facilities built a decade ago.

locations, and the difference between these two costs is the congestion rent that can be earned by generators in the constrained-off location. Significant rents may be created for both the generators and the holders of transmission rights able to deliver to that area. Godby et al. (2014) explore the challenges presented by the location of wind resources when required transmission capacity is not available to deliver power to market. The authors find that the price effects caused by changes in power output at intermittent sources are strongly dependent on supply conditions and the presence of market distortions caused by transmission constraints.

The spatial location of renewable and non-renewable generation source is also important in its impact on aggregate and local emission outcomes. The spatial location of wind relative to traditional generation sources and demand centers matters when considering the impact on local pollutants. Wind generation may displace fossil-fueled plants traditionally located near demand centers, lowering the local pollutants present in that area (Fell et al., 2018). Congestion, however, may increase such pollutants, and overall, changing the pattern and mix of generating sources on an electricity grid may have unintended effects on spatial pollution emission outcomes. Moving from a case where transmission capacity constraints exist to one where the region is completely integrated may also have beneficial or unintended negative impacts on local pollutants due to changes in the patterns of generation they create across a power system. The aggregate pollution outcomes of local pollutants, and associated regional damages, depend entirely on what type of generator, and where that generator is located, is being offset by wind generation elsewhere in the system.

While several studies (Naughton et al., 2013; Roques et al., 2010; Milligan and Artig, 1998; Drake and Hubacek, 2007) have sought to empirically quantify the benefits from wind diversity, these analyses have been simple in that they assume a constant return to electricity generated and ignore many of the complexities inherent electricity markets, such as time-varying prices and congestion effects.[9] These studies also consider only market benefits, ignoring the potential benefits in terms of emission reduction. It is important to policy-makers to understand the grid-cost dynamics of wind generation and the system-wide transmission outcomes, and the potential congestion rents generated by greater wind capacity. Geographic diversity might indicate that a particular spatial distribution of wind resources results in the greatest power production with minimal disruption, but transmission constraints can change the system impact of that same portfolio of wind turbines, to the point that it may mitigate any benefits of geographic diversification. Time- varying prices and congestion must be accounted for if the potential of geographic diversification is to be understood. Considering the problem of energy planning from an investment-planning perspective, it is worth valuing both the benefits of additional wind generation as a low-cost and emissions-free generation source, diversification of those wind resources to reduce variability, but also the benefits of additional transmission capacity on a transmission-fixed grid.

[9] These papers also do not consider time varying cost of back-up resources, nor do they consider how changes in the availability of resources on the grid or transmission congestion may affect such costs.

In this paper, we use a simulated dispatch model of the Rocky Mountain Power Area to to provide a case study that generates the necessary data to analyze and compare the costs and benefits to the system from additional wind generation and geographic diversification. In the Rocky Mountain Power Area (RMPA), Wyoming and Colorado are both home to rich wind resources that are diverse across the region. Both states have been expanding their wind power generation, where Wyoming looks to export, and Colorado has a need to import the wind power, and export any excess electricity produced. On average, sites across Wyoming exhibit higher capacity factors than those in Colorado, though with a higher variance of wind speeds. We explore the impacts of different spatial configurations of additional wind generation across the system under transmission constraints and varying degrees of transmission congestion. Using a dispatch model allows the analysis to consider variation in the value of electricity during hours of the day and times of the year as our dispatch model simulates the supply and demand conditions present in each hour. Given a system operator's preferences over the outcomes of the electricity market, the benefits of geographic diversity can be mitigated by the distortions caused by congestion. However, if system reliability is at least as important as achieving lowest-cost electricity generation, the benefits of geographic diversification are realized even under transmission constraints. In addition, we find that in the case of carbon dioxide emissions, that greater geographic diversity results in the greatest abatement of aggregate emission outcomes.

2. Modeling Framework

Our study builds from two preliminary investigations into the geographic diversity of wind resources across Wyoming and Colorado (Naughton et al., 2013) and the impacts of transmission congestion on a regional grid (Godby et al., 2014). Wyoming and Colorado compose most of a local electricity region known as the Rocky Mountain Power Area (RMPA).[10] Power to retail customers is primarily supplied by three regulated investor-owned utilities and several much smaller municipal utilities and rural electric associations. These entities engage in generation and/or purchase wholesale power through bilateral trades with suppliers of electricity. Generation facilities are located throughout the RMPA, however renewable sources; specifically, wind generators are primarily located in central Wyoming and northeastern Colorado. Transmission access to deliver generated power to RMPA load-centers may be scheduled through utilities' own transmission facilities or through two transmission networks (Godby et al., 2014).

Between 2007 and 2010, Wyoming's wind generation capacity more than doubled from 288 MW to over 1410 MW of potential capacity, where no additional generation capacity is added in subsequent

[10] The United states electricity system is composed of three separate grids. The western grid, commonly called the WECC (for Western Electricity Coordinating Council) covers more than 1.8 million square miles. with WECC's members, representing all segments of the electric industry within the Western Interconnection, provide electricity to 71 million people in 14 western states, two Canadian provinces, and portions of one Mexican state (Transmission Agency of Northern California, 2017). The RMPA is one of four reporting areas in the WECC and provides power to over 5.5 million people within all or parts of five U.S. states: the entire state of Colorado, eastern and Central Wyoming, portions of western South Dakota and Nebraska, and a small area in the extreme northwest corner of New Mexico (Godby et al., 2014).

years. In Colorado between 2008 and 2012, wind generation capacity increases by nearly the same percentage from just over 1000 MW to 2300 MW. Colorado's potential capacity of generation increased to nearly 3000 MW by the end of 2015. Wyoming is regarded as a top state for future renewable generation and several developers are currently looking to build new wind turbines in Southeastern Wyoming. Colorado state's Renewable Portfolio Standards are also anticipated to encourage more growth in renewable generation in the years to come. New wind development projects are subject to regulatory standards are procedures and are driven by private entity's goals, and the size of individual wind plants are growing. Identifying resources with good diversity may be important to inform policy and help coordinate better wind power deployment across both states in the future in the future.

In our case study we consider several proposed sites for new wind development across Wyoming and Colorado. We use the National Renewable Energy Laboratory (NREL) National Integration Wind Dataset (WIND) toolkit to build a wind data set spanning five years from 2008-2012 that contains estimates of existing and hypothetical wind site production across the region.[11] Using this data, we can examine candidate sites for good diversity as in Naughton et al. (2013). To incorporate the true value of the electricity produced given the time of day we use the modeling framework of Godby et al. (2014) to simulate price outcomes for the RMPA with additional wind generation according to different spatial distributions and transmission constraints. We can use the solutions from the simulated dispatch models to analyze and compare system outcomes under different objectives.

To investigate diversity, we employ a scenario design like that in Naughton et al. (2013). We select five sites across Eastern Colorado and Southeastern Wyoming, where wind generation capacity is the greatest and are likely sites for future development. We explore three sites in Colorado that represent large extensions of existing wind farms: Colorado Green, Kit Carson and Peetz Table. We explore two new sites in Wyoming, named for the respective developers interested in building in those locations: Pathfinder and Viridis. In figure 2 we can see the distribution of the proposed sites along the region. If diversity is determined only by distance this implies that pairs of sites with the greatest distance between them, have the greatest diversity. Therefore, Colorado Green and Pathfinder should have better diversity than Colorado Green and Peetz Table, or Pathfinder and Viridis. We also expect that pairs of sites across state lines have display better diversity due to the fact that winds in Wyoming and Colorado are created by different weather processes and result in different patterns of daily and seasonal winds.

Using WIND toolkit estimates of power (MW) output at 100-meter hub-heights were obtained for geographic locations that most closely match sites we believe are good candidates for future wind

[11] The WIND Toolkit is a publicly available meteorological data set of wind power production time series, and simulated forecasts, that are created using the Weather Research and Forecasting Model run on a 2-km grid over the continental United States at a 5- minute resolution. The validity of the WIND toolkit power estimates has been extensively discussed (Draxl et al., 2015).

development in Wyoming and Colorado. 5-minute output is collected for the years 2008 to 2012. The power estimates at 100 meters are extrapolated to an 80-meter hub-height[12] (which we assume to be standard across our hypothetical sites) for a GE 1.5 MW turbine. [13] We assume that each diversity site comes online at the beginning of 2008, and additional adjustments are made to power estimates to reflect maintenance and age over time. It is assumed turbines are offline one week a year for maintenance, and after two years of age, are discounted to reflect more frequent shut-downs. E ach site is assigned a total generation capacity. The diversity sites were sized to represent a significant increase in wind power generation but are also sized according to the potential capacity of wind resources available at the respective location. The total generation capacities and estimated capacity factors of the diversity sites are summarized in Table 1[14].

Unlike Naughton et al. (2013) that assumes constant capacity factors across sites, we estimate hourly capacity factors for each site, given the wind conditions at each hour across the five year simulation. Overall, wind conditions modeled using the WIND Toolkit data suggest that Colorado Green in Colorado has the highest potential capacity factor of the sites we consider, averaging near 42 percent, which is comparable to the average capacity factors of 42 percent and 38 percent at the two Wyoming wind sites. We find, however, that the other sites in Colorado have poorer winds. Note also that while Colorado Green may have significant wind resources, it also has a high variance, close to the higher wind variances seen at the Wyoming sites. Overall, summary statistics suggest geographic diversity may help to reduce the overall variance of wind production if we combine strong wind sites across locations.

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[12] We use the power law to come up with a ratio of wind speeds at 100 meters to 80 meters and use this ratio to adjust power outputs. The power law is defined as $v_2 = v_1 \frac{z_2}{z_1}^{\alpha}$ where v_1 and v_2 are the velocities (m/s) of the wind at two respective turbines at different heights of z_1 and z_2 meters. α is defined as the roughness coefficient that defines the surrounding terrain, or the shear roughness, of the turbine. We used a value of $\alpha = 0.2$ which is described as "Agricultural land with many houses, shrubs, and plants, or 8 meters tall sheltering hedgerows within a distance of about 250 meters" (Ragheb, 2017). From the calculation of the power law we get a constant ratio of wind speeds and use these ratios to adjust the power estimates of a 100-meter wind speed to 80 or 60 meters.

[13] These turbines were typical of the type of technology employed during the study period. Typical turbines now employed are between 25 percent and 50 percent larger than those used during our study period. We do not consider the use of such newer turbines in our study and how they might change the results.

[14] Note that the maximum produced power is never full potential of a site. This occurs for two reasons. First, we assume maintenance occurs at each site, where each individual turbine is offline for a week in an entire year. If we consider a 900 MW site that is made up of 600 turbines, we assume 12 turbines must be offline each week of out of the year, reducing potential capacity by 18 MW. Second, the sites presented here are aggregates of several individual sites in the NREL data, where each NRELsite corresponds to a 16 MW block (made up of around 11 turbines). We aggregate these blocks to create 100 MW cluster consistent with how large wind farms are often build and operated – as smaller clusters of turbines within a larger set. These 100 MW clusters are then further aggregated to create the sites shown in Table 1. For an aggregated cluster of sites with a total potential capacity of 900 MW to ever produce at near 100 percent capacity requires that each individual modeled turbine be at full capacity at the same time – that is 600 turbines all producing at 100% in the exact hour. In reality this is very unlikely. There is never a time when all turbines in all 16 MW NREL sites simultaneously operate at 100 percent output. The correlations across sites within aggregated clusters also differ resulting in the outcome that modeled farms differ with respect to maximum simulated output.

Naughton et al. (2013) argue that pair-wise correlation coefficients between wind sites provide the best measure of geographic diversity, where lower correlation indicates better diversity. When the correlation coefficient is one, the winds at the two locations follow each other exactly (perfectly correlated). When the correlation coefficient is zero, the winds at the two sites are uncorrelated. In Table 2 we calculate the correlation coefficients of wind power production for each pair of sites. The pair-wise correlation coefficients that are highlighted represent the pairs that are good candidates for diversity using Naughton et al.'s criteria. As expected, pairs of sites across the two states make better candidates for diversity, as the correlation falls as the distance between two sites increases. Each site in Wyoming, Pathfinder and Viridis, have the lowest pair- wise correlation coefficients when combined with any site in Colorado. The lowest resulting correlation coefficient occurs when Pathfinder or Viridis is paired with Colorado Green, achieving a 4 percent correlation, while the Viridis-Colorado Green pairing has a 7 percent correlation. Pairs of Colorado-only sites have correlation values closer to 50% and combining Wyoming-only sites results in a correlation of approximately 79 percent. These estimated correlations are comparable to those estimated in Naughton et al. (2013) for sites in similar locations even though different wind data is used in each study. These results verify their observation that more generally, the greater the distance between wind farms, the greater the potential benefits from reducing correlated wind patterns, even though our data is much finer in its detail than the earlier study.

While overall correlation coefficients tell an interesting story, averages taken across the entire period absorb much of the seasonal and annual variation. In Table 3 we estimate pair-wise correlation coefficients by season for the five-year simulation period. Wyoming winds are at their highest in the winter months and decline significantly though the spring and into the summer before increasing again in the fall. Colorado winds generally perform well in the spring, but also experience a decline into the summer. We find that seasonal correlation coefficients between sites are even lower between Wyoming and Colorado sites than the overall correlation coefficients. Potential benefits based on seasonal Colorado-Wyoming pairwise correlation coefficients appears to be strongest between the months of December to April and poorest between the same sites during the months of May to September.

We also consider the diurnal pattern of wind resource across the sites, as daily fluctuations in wind power production can be important if wind speeds peak in hours that do not correspond to peaks in demand. We find that for our estimated capacity factors, both Wyoming and Colorado peak most often between the hours of 11 pm and 12 am, however, the correlation coefficients between the maximum wind production hours are relatively low when compared to the overall site correlations, indicating that at least when combining sites across the two states, they more often do not produce at their highest capacities in the same hours. Figure 3 depicts the diurnal trend for each site, averaged across each day in the five-year period. Site comparisons between Wyoming and Colorado reveal that they do not peak at the same hour on the same day more than 6% of the time, on average across our period. We find that the two Wyoming sites, Pathfinder and Viridis, follow similar diurnal trends throughout the period, where Viridis tends to exhibit higher average capacity factors and there is less variaton over a 24-hour period on average than compared to sites in Colorado. The three sites in Colorado, Colorado Green, Kit Carson and Peetz Table follow similar diurnal patterns relative to each other, with Peetz Table performing most poorly on average. In a 24-hour period, we see that capacity factors at all Colorado sites are higher in the early morning hours, but decrease into the late morning, only to pick up again in the evening. The U-shaped diural pattern across Colorado wind sites also is suggestive of why combining Colorado wind sites with those in Wyoming may be more beneficial to reducing the variability of wind resources across the two states. The Figure also suggests though that the combination of wind sites that provide the greatest value in electricity generation may be unclear given the fact that Wyoming wind sites produce greater output during daylight hours when typically, power prices are higher. Such conclusions, however, may be misleading as Figure 3 is smoothing out seasonal variations that are equally important to consider.

Figures 4 to 7 describe average diurnal patterns across the five-year period for each site for each season. It is evident that seasonal wind patterns are important. In the winter, Wyoming winds are at their strongest, the capacity factors for the sites Pathfinder and Viridis lie well above the three Colorado sites throughout the 24-hour period. In the spring, however, Wyoming winds tend to fall, and Colorado Green, Kit Carson and Peetz Table perform better on average. Wyoming winds are stronger in the afternoon hours, before Colorado winds pick up again, while in summer months Wyoming sites perform relatively poorly on average, where Colorado sites still peak in the late evening or early morning hours. Only in the fall do we observe the familiar U-shape for the sites in Colorado, and more steady and strong winds from Wyoming sites. Overall, observation of wind patterns suggests wind generation can differ greatly across locations and while combining sites may reduce system variation in wind generation, diversification across the region could reduce the potential value of total wind production due to differences in in time of day electricity pricing. This suggests a more detailed analysis is necessary to determine the actual potential benefits or costs from combining wind generation sites.

To assess the real benefits of geographic diversity, one must consider how valuable the total wind power production between pairs of sites is, as determined by the time of day it is produced and the observed demand in that hour. Furthermore, one must also consider how locating wind sites and their patterns of production may affect transmission congestion on a transmission-constrained system. The occurrence of transmission congestion could also mitigate or emphasize the system benefits of geographic diversity. To address these concerns and analyze the impact of increased wind generation, implementing geographic diversity in site selection, transmission and policy issues within the RMPA, we use a Decoupled (DC) power-flow modeling framework to model hourly generation price and generation outcomes as an approximation of the actual AC system, as in Godby et al. (2014).

The modeling framework follows the nodal pricing model outlined by Green (2007) and formalizes the choice of generation sources used (referred to as “dispatch”) to serve a given demand or “load” subject to the technical constraints of the electricity network. The simulation model maximizes estimated producer surplus, or minimizes system cost, in a competitive electricity wholesale market on an hourly basis. Using actual data from 2008 to 2012, hourly generation, price outcomes and network congestion conditions are simulated. There are two types of generation sources: (i) traditional and non-intermittent sources including fossil-fuels (coal and natural gas) and hydro-electric, and (ii) wind generators whose cost and capacity conditions reflect the local stochastic climate conditions. We take reported hourly demand within the region as given, making the demand modeled perfectly inelastic at a point in time, in the short run. The relevant cost of electricity generation is the variable cost of producing power output measured in megawatts (MW) and ignores fixed costs of production. Using the model output, we compute hourly estimates of efficient market prices by solving Equation 1 subject to the constraints described by Equations 2 to 5:

$$\max_{\omega} = \sum_{i=1}^{I} p_i d_i - \sum_{i=1}^{I} \sum_{j=1}^{J} c\,(\omega_{i,j}) \qquad (1)$$

$$\bar{\omega}_i = \sum_{j=1}^{J} \bar{\omega}_{i,j} \qquad \text{(generation capacity constraint)}, \qquad (2)$$

$$N + \sum_{i=1}^{I} \sum_{j=1}^{J} \omega_{i,j} = \sum_{i=1}^{I} d_i - \lambda \qquad \text{(energy balance constraint)}, \qquad (3)$$

$$\left| d_i - \sum_{j=1}^{J} \omega_{i,j} \right| = |\vartheta| \leq \vartheta^{\max} \qquad \text{(transmission line flow constraint)}, \qquad (4)$$

$$\bar{\omega}_{i,j} \geq \omega_{i,j} \geq 0 \qquad \text{(individual generator production constraints)}. \qquad (5)$$

The associated Lagrangian for the problem, suppressing constraints (2) and (4) for clarity is

$$\mathcal{L} = \sum_{i=1}^{I} p_i d_i - \sum_{i=1}^{I} \sum_{j=1}^{J} c(\omega_{i,j}) - \mu^{\mathrm{e}} \left[\sum_{i=1}^{I} d_i + \lambda - N - \sum_{i=1}^{I} \sum_{j=1}^{J} \omega_{i,j} \right] - \mu^{\mathrm{t}} \left[|\vartheta| - \vartheta^{\max} \right], \qquad (6)$$

where d_i is the net demand at node i, p_i is the price of power at node i, and $c(\omega_{i,j}$ is the cost to generate power $\omega_{i,j}$ at generator $\mathbf{j}$ in node i, where i $=$ 1, 2. We model the RMPA as a two-node system network. Marginal costs at each generator are modeled as constant. The total cost of power at each generator is thus the product of the marginal cost, c and the amount of power generated ω at each generator in each node, and the total cost of generated power is the sum of all individual generators **j** across both nodes i. The flow of power along the transmission line connecting two nodes i $=$ 1 and i $=$ 2 is denoted by ϑ. The transmission line has a fixed capacity of $\vartheta^{\max}$. Flow on the transmission line is defined as the difference between demand and supply of power within each node. The energy balance constraint equated the sum of total demand plus the total line losses, λ, to total supplied energy which includes total generated power and N, the exogenous system net imports of generated power from outside the RMPA. The Lagrange multiplier μ^e is associated with the energy balancing constraint and μ^t is the multiplier associated with the transmission line capacity constraint. The first-order conditions of the Lagrange with respect to the optimal choice of generator output (dispatch) taking constraints and net imports as given, can be used to define the optimal price at each node in the 2-node system as

$$p_i = \mu^{\mathbf{e}} \left[1 + \frac{\partial \lambda}{\partial d_i} \right]. \tag{7}$$

In the absence of transmission line losses, μ^e is equal to the marginal cost of generation in the node defined to contain the last unit of generation employed in an optimal (cost-minimizing) dispatch, plus any chance in line losses. Changes in demand may change line losses. The partial derivative may be positive or negative. The second term in this equation represents how line constraints affect marginal costs at each node. When the transmission constraint is non-binding ($\mu^t = 0$) the price in the two nodes is equal.

Consider a cost-minimizing outcome in the two-node system and suppose that in the optimal solution the combined load of both nodes is just met by the combined generation in each node, with the last unit of generation dispatched in the up- stream node. If a single transmission line operates between the two nodes, and is just at maximum capacity, any additional unit of demand added at the downstream node will require additional generation to take place in that node and the transmission constraint will be binding. When the transmission constraint is binding we say that transmission congestion occurs and the price in node 2 will differ from the price in node 1. The price in node 1 will equal the price of the marginal unit of generation there, where the price in node 2 will equal the price of the marginal generation at the new source of generation. The value of the multiplier on the transmission constraint is therefore equal to the difference between the marginal costs of the last generators dispatched in each node.

To simulate hourly outcomes in the modeled region taking into account changes in wind production, transmission line capacity and hourly demand in the model, we reduce our model of the RMPA to a two-node system shown in Figure 8.[15] In our model, Node 1 consists of all areas in the RMPA

[15] Such a simplification is consistent with other published results including DOE (2009).

north of the Wyoming border and Node 2 includes all areas south of the Colorado-Wyoming border. Power can flow between Wyoming and Colorado only using a transmission pathway referred to as Path 36/TOT3. The transmission line TOT3 has a nominal capacity of 1605 MW but the actual hourly transmission limit varies due to generation and load conditions, weather and temperature, maintenance operations and configuration changes. The average demand between 2008 and 2012 in Node 1 is 780 MW and in Node 2 is 6825 MW. WECC Path Data is used to define N, power flows into and out of the RMPA region to other regions in the western grid. Power flows out of the RMPA were added to total nodal loads, while flows into the RMPA were subtracted from nodal load data. To identify specific hourly generator capacities in the RMPA, generator capacities by site were defined using EIA form 860 data for over 360 individual intermittent and non-intermittent sources. Within the RMPA, fuel sources include coal, natural gas, hydropower, diesel fuel, renewable gases, wind and solar power. The total generation capacity in Node 1 is 3683 MW and in Node 2 is 17,760 MW by the end of 2012. Growth in wind resources is significant over the five-year period from 2008 to 2012, while growth also occurs in coal generation, particularly in Node 1.

Hourly simulations solve the dispatch model using estimated generator marginal costs, generator capacities for traditional generators, simulated wind capacities using the NREL WIND Toolkit power estimates for each wind farm in the RMPA, actual RMPA demand data and observed transmission constraints hourly from 2008 to 2012[16]. The RMPA included 44 wind farms between 2008 and 2012. To model the wind at each location the NREL WIND Toolkit (described in the previous subsection) was used to estimate hourly capacity factors at the nearest locations modeled by NREL to each of the RMPA wind farms, to simulate power outcomes. Hourly balancing-area load-data from Federal Energy Regulatory Commission (FERC) Form 714 was used to define nodal demands. Since balancing areas do not correspond to the nodes defined in the simulations, we define two different demand cases. The first case assumes underlying demand is similar on a per-person basis in each node and annual county-level census data from 2008 to 2012 was used to define nodal demands as the population-weighted shares of the total load. This case leads to a pair of markets where Node 2 accounts for about 88% of the total RMPA load. The second case defines a ratio of state demand based on EIA estimates of state demand for electricity use and leads to estimates where Node 2 only accounts for about 75% of total load. To differentiate the two demand cases, and to investigate how the change in nodal demand shares impacts the occurrence of transmission congestion, we term the first case to be the "high congestion" case, and the second to be the "low congestion" case, as we suspect less downstream nodal demand should ease transmission congestion. Hourly demands are treated as perfectly inelastic and exogenous to the model. The ability of the grid to maintain low generation costs depends on transmission constraints present in the system. Simulation output in each hour identifies nodal electricity prices, generation by each facility, and hourly transmission flows to determine system and nodal power and price outcomes.

[16] The model does not currently consider limits in generator ramping rates – limits in individual generators' ability to increase or decrease generation levels. Future modeling will include such limits to both reflect more realistic operation and to determine if such limits change results significantly.

We simulate hourly generation and price outcomes of the dispatch model as an extension to Godby et al. (2014) over a five-year period from 2008 to 2012. Results are produced simulate the model under the two demand share cases ("high" and "low") with and without transmission constraints. Our goal is to then add pairwise combinations of the wind sites described in Table 1 to determine how differences in spatial diversity affect simulation outcomes under different demand and transmission congestion conditions. In total, fifteen 5-year hourly simulations are created: three "baseline" cases and 12 "diversity" scenarios that each include an additional 1800 MW of wind generation capacity under the constrained demand cases, and the unconstrained case as described in Tables 4 and 5. Using scenario results, we compare outcomes to determine how the choice of wind farm location affects system outcomes to determine if the implementation of wind diversification creates benefits similar to those earlier studies suggested while simultaneously considering how differences in hourly load and potential transmission congestion affect observed outcomes. Our previous analysis of diversity indicates that the pairs of sites between Colorado and Wyoming in diversity scenarios 2 and 3 should most consistently produce wind power. In adding a large amount of wind power, we are effectively shifting the supply curve to the right and displacing the highest marginal cost generators in favor of cheaper wind power thus we expect in all scenarios electricity prices will fall, however, it is unclear how average hourly prices and therefore the overall cost of electricity will be affected by different spatial combinations of wind development.

Greater spatial diversity of new wind sites should reduce the overall variance of wind power production, and therefore reduce hourly price variance relative to each scenario. Table 6 summarizes the wind power production of each combination of diversity sites to be added to the baseline model of the RMPA. We can see that Diversity Scenario 2 and 3 have the lowest overall variance of wind power production. The average capacity factors are around 40% for each scenario, making the aggregate power production in each of these scenarios quite similar but Diversity Scenario 2 has the lowest variance and Diversity Scenario 3 has the highest capacity factor. The solutions of the dispatch model will illuminate how an additional 1800 MW of wind affects system outcomes, and how these system outcomes differ when transmission constraints exist.

3. Results

Electricity price outcomes were solved using the dispatch model and incorporating actual RMPA demand (load) and transmission constraints, estimated generation costs and wind conditions over the 43,841-hour period simulating January 1st, 2008 starting at 12:00 am to December 31st, 2012 at 4 pm (using Mountain Standard Time zone). The simulation was programmed using GAMS.[17] We first consider a simulated un- constrained transmission solution in which no transmission capacity constraint was imposed between Nodes 1 and 2. We simulate the unconstrained transmission solution (hourly transmission constraints are suspended between nodes 1 and 2 for five scenarios: the baseline case, and the four spatial diversity scenarios described in Table 5. The baseline scenario serves as a

[17] General Algebraic Modeling System (GAMS). GAMS Development Corporation (www.gams.com).

benchmark that models the outcome of the existing system where no additional wind capacity is added. The diversity scenarios each simulate an additional 1800 MW of installed wind capacity added to the system over a different combination of locations across the two nodes. We then simulate the transmission-constrained solution for the same four diversity scenarios to investigate how the system outcomes change when congestion is possible. We solve the constrained solution for the four scenarios under the two different nodal demand conditions to consider impacts on transmission congestion when the demand shares across the two nodes are changed. In what we denote the "high congestion" case, a greater share (on average, 88 percent) of total hourly demand occurs in Node 2 (Colorado) and as electricity flows are generally North to South in our system, this solution is expected to result in larger price congestion. In the "low congestion" case, most of the demand share is still in Node 2, but because on average Node 2 only represents 75 percent of total hourly demand in the system less transmission congestion is expected as less power will be transferred from Node 1 to Node 2 compared to the "high congestion" case. Overall, this design allows us to investigate the potential benefits of greater geographic diversity, and how these benefits may change in the presence of transmission constraints.

No Transmission Constraints

When the transmission constraint is not binding, there is a single market clearing price that occurs across Node 1 and Node 2. We solve the unconstrained solution for the baseline scenario i.e. the scenario that best represents the existing generation capacity of the RMPA system for our time period. The baseline scenario acts as a benchmark to understand how the system changes when an additional 1800 MW of wind capacity is then added. Wind generation sources are nearly zero-marginal cost sources, so whenever wind power is being generated by a turbine, it is serving demand. Therefore, the additional 1800 MW of wind generation shifts the electricity supply curve to the right by the added capacity thus resulting in a significant decrease in hourly prices across all diversity scenarios when compared the baseline.

In Figure 10 we can see that, over time the average baseline yearly price across the system is falling. This occurs because in the baseline model there is a significant increase in wind capacity in Colorado each year from 2008 to 2012, and in Wyoming between 2008 and 2010. A large increase in existing cheap wind generation lowers the system prices, even before the additional diversity wind sites are added. In the diversity scenarios we double the existing wind capacity at the beginning of our time period, so we see a relative drop in the market price of electricity from the baseline case in 2008, of about 17-18% depending on where the additional wind was located. The price differences are less pronounced in subsequent years, where the diversity scenarios result in around a 11-12% price decrease relative to the baseline scenario.

Relative to the baseline, the additional wind generation in all the diversity scenarios lowers average electricity prices. Given observed demand in every hour, we can calculate the total cost of electricity consumption (price times demand in very hour) and sum across all hours and compare the total electricity cost outcomes across the scenarios. These results are presented in Table 7. Recall that a system operator aims for lowest- cost generation to meet demand. Additional wind generation is an additional lowest-cost generation source that the system can take advantage of. Intuitively, any diversity scenario results in lower electricity prices across the system relative to the baseline. When we compare system outcomes across diversity scenarios, we find that Diversity Scenario 3 which combines wind resources in Colorado Green (Node 2) and Viridis (Node 1) results in the lowest total electricity consumption cost. The second lowest cost scenario, however, occurs under Diversity Scenario 4 when all new wind production occurs in Wyoming due the higher average output in Wyoming over daylight hours. Overall, while all scenarios lower prices relative to the baseline, these results suggest that greater geographic diversity translates into the greatest cost-savings in electricity generation if both strong wind resources and geographic diversity are considered. Diversity benefits, however, may be mitigated if they preclude the use of higher output wind resources. Our results indicate that trade- offs do exist in the system when we consider increasing renewable generation capacity – greater diversity may reduce system generation variance across renewable sources but reducing that system generation variance may occur at the expense of higher system costs.

Table 8 presents the summary statistics of the price outcomes across the scenarios. The comparisons of the average prices across the years reveal the same outcomes as we previously described, though we notice that the price variance that results from each of the scenarios are not statistically significantly different from each other. We might expect that greater geographic diversity, because it minimizes the fluctuations of renewable generation in the market, might also translate into lower price variances. These simulations, however, suggest that in the unconstrained system, these effects are not notable.

Transmission Constraints - High Congestion

In the previous section, results established that potential benefits from geographic diversity in balancing the costs and benefits of additional renewable resources being integrated into an existing electricity grid, but these results were presented in context of an unconstrained electricity grid. In reality, a lack of transmission infrastructure is a very real hindrance to the growth and efficient utilization of renewable resources. Consider the same scenarios under the existing hourly transmission constraints for the RMPA. There is limited transmission capacity to transmit power to market when it is available between the two nodes. When the transmission constraint is binding, congestion occurs and there is a different market clearing price in each node. We define the price differential here as the Node 2 price less the price in Node 1 in any period. When the differential is negative it implies power flows from Node 2 to Node 1and when the differential is positive the opposite occurs. In the simulations solved under the high-congestion demand case (where 88% of the total load is accounted for by Node 2), it is never the case that negative price differentials occur thus the flow of power is always from Node 1 to Node 2 and congestion never occurs when or if power flows in the opposite direction. Mitigating congestion would require location of any new wind resources in Node 2, despite the fact that this may increase the intermittency (variance) in wind generation, introduce a new potential tradeoff. Such a tradeoff may not always be present when congestion is possible though. The low congestion demand case (when 75 percent of RMPA load is located in Node 2) does result in negative price differentials and it may not necessarily be true that locating new resources on one side of a transmission link is always preferable.

Table 11 contains the average price and congestion outcomes by year, for each scenario under transmission constraints and high congestion demand conditions. Looking at the baseline scenario results we see that when transmission constraints exist, price congestion arises causing a wedge between the two nodal prices. The constraint causes the price in Node 2 to rise relative to the unconstrained price, while the price in Node 1 is falling relative to the unconstrained price. The magnitude of the price differential is rising each year, and the percentage of hours where congestion occurs each year rises from 1.59% of the time in 2008, to nearly 100% of the time in 2012. Whenever congestion occurs, it causes the downstream node to have a higher relative price. Even further, observed increases in cheaper wind energy in Node 1 contribute create transmission congestion over time, causing Node 2's prices to rise further.

Consider what happens we add additional wind generation to the system when transmission constraints are present. We found previously that in the unconstrained case relative to the baseline, regardless of where the wind was added, the large influx of cheap power reduced the system-wide price and reduced the relative price variance. When transmission constraints are present though, market outcomes change as a result of congestion. In Table 11, each diversity scenario still results in average nodal prices that are lower than the nodal prices in the baseline case. When at least half of the new wind capacity is added in Node 1 (Diversity Scenarios 2, 3 and 4), we see that the incidence of price congestion is drastically higher than in the constrained baseline scenario. On the other hand, when all of the additional wind capacity is built in Node 2, this increase in cheaper generation in the downstream node eases some of the congestion and therefore the price differential and percent of hours with congestion are reduced relative to the baseline case. Considering the impacts of transmission constraints, it is no longer clear whether there are benefits from greater geographic diversity. The more spatial diversification that occurs, the more cheap wind is located upstream and the higher the occurrence of congestion. We can see in Figure 11 that all of the price differentials are rising over time, but the most pronounced price differential occurs as early as 2008 in Diversity Scenario 4. An additional 1800 MW of cheap wind generation being located only in Node 1, when there is not enough demand to consume all of the electricity generation, causes a greater occurrence of price congestion and therefore blocking any spatial diversity benefits with respect to wind generation to be lost. All diversity scenarios in the high congestion demand case reduce the price variance faced in each node, but the variance of the price differential is the same or higher in all diversity scenarios when at least some of the wind capacity is built in Node 1. We also find that despite the fact Diversity Scenario 1 works to ease the effects of congestion, this scenario still has relatively higher price variance for each node when compared to Scenarios 2 and 3 with greater geographic diversity.

While it is still the case the additional wind generation lowers market prices relative to the baseline, it is the case that transmission congestion reduces these benefits. Relative to the unconstrained market outcomes, each scenario results in a higher average system price. We again calculate the total electricity consumption cost for each scenario in Table 9. In the transmission constrained scenarios, we find that the impact of different allocations of the additional wind generation depends on which node is considered. Relative to the baseline, nodal prices are reduced most if all of the additional wind is placed in that same node. From the system perspective we find that total electricity consumption costs are minimized in Diversity Scenario 1. This outcome is in stark contrast to what was previously found. The benefits of geographic diversity or even of the strong wind resources in Node 1 cannot be fully realized due to the high occurrence of transmission congestion that increases the more wind is placed outside of Node 2.

Considering the resulting variance of renewable power in the transmission constrained cases is less straight- forward than before. We can see that transmission constraints reduce the benefits of renewable generation if that power cannot be delivered to market when it is available. In some hours, this can result in wind curtailment, particularly when new wind resources are located in Node 1 where there are strong winds but much less demand. Wind curtailment acts to smooth out fluctuations in wind power generation, but it is an action taken by the system operator because too much renewable power is being produced relative to demand. In actuality, the total amount of potential renewable power that could be produced is still the equivalent to the no transmission constraints cases – but how much of the power is used is impacted by the transmission constraints, as are electricity prices in both nodes.

Transmission Constraints – Low Congestion

Table 12 summarizes the average price and congestion outcomes by year, for each scenario under transmission constraints and low congestion when only 75 percent of total load is located in Node 2. Generally, in this case we find that power usually flows north to south, but there are times when it is possible that enough power flows upstream from Node 2 to Node 1 to cause transmission congestion to occur, and a negative price differential occurs. Relative to the previous set of scenarios where transmission constraints existed, there are far lower incidences of price congestion in this case. The greater share of demand in Node 1 works to ease some of the congestion. In the baseline scenario it is still the case that when congestion occurs, the downstream node, Node 2, has higher prices relative to the unconstrained case while Node 1 has lower relative prices, however a t-test of the mean price for each node reveals that the nodal prices are not statistically significantly different from one another. In the baseline scenario we see that price congestion is zero in 2008, and then negative in 2009, and then is positive and very small again in 2010 and continues to rise slowly until 2012. The occurrence of a negative price differential occurs when there is enough load in Node 1 and a higher availability of cheaper wind generation in Node 2 to cause congestion. By the end of 2010, however, increases in Wyoming's installed wind capacity increases significantly and alleviates the occurrence of negative price differentials after 2009. Diversity Scenario 1 (locating all 1800 MW of new wind in Colorado) eases congestion the most compared to the baseline, except for 2009, when there is a higher negative price differential than in the baseline case. The reason for the reduced congestion over the entire simulation period in Diversity Scenario 1 is the same as previously, this scenario locates all new wind resources in the node with the greatest demand, reducing the need for imported power and congestion from Node 1. When new wind resources are located in part (diversity Scenarios 2 and 3) or entirely (Diversity Scenario 4), the greater demand in Node 1 eases some of the congestion present in the high congestion demand case by reducing the available electricity for export in Node 1 and reducing the need for imported power from Node 1 in Node 2. Even though congestion happens more frequently as more wind is added in Node 1, the impact of the transmission constraints is far milder than in the previous case. In the worst scenario, Diversity Scenario 4, the percent of hours of congestion per year is never higher than 68%, as compared to the high congestion demand cases when hours of congestion exceeded 60% of total hours per year by 2010.

Table 10 results also indicate the fact that the presence of transmission congestion can create counter-intuitive results. While the additional wind generation created in Diversity Scenarios 1 through 4 lowers electricity consumption costs relative to the baseline, we find that when transmission constraints exist, but there is relatively more demand in Node 1, that the system cost of electricity is minimized in Diversity Scenario 4. We also find that not all the benefits of geographic diversification are mitigated, as Scenarios 2 and 3 do perform better than Scenario 1. Overall, the cost of electricity consumption is reduced in Diversity Scenario 4 despite the increased congestion this situation creates, in part because price increases in Node 2 are offset by greater price decreases in Node 1. Again though, consumer welfare would depend on the node the consumer is located in as consumers in Node 2 are worse off than in other diversity scenarios, while those in Node 1 are better off thus congestion not only changes the total overall realized system costs but the distribution of benefits and costs across consumers in the system.

Emissions Outcomes

Our current analysis only considers carbon dioxide emissions[18]. Carbon emissions can be calculated for each coal or gas generator for every hour that it is on, according to its fuel inputs and heat rate. Total carbon emissions for the system are calculated by aggregating over all hour's emissions. Without any additional wind, we estimate that in the unconstrained system over the five-year period, we produce 247,471,926 tons of carbon dioxide. When transmission constraints exist and there is high congestion, the emission level rises less than 0.05% while in the low congestion case the emission level is even higher, about 0.7% higher than in the unconstrained case. To understand why transmission constraints, without expanded wind generation, change emission outcomes even if modestly, we should think about the supply curve. When the upstream node is unable to export

[18] Estimating local pollutant emission requires consideration of each generators' fuel input, boiler and scrubber technology, location, time-of-day and hours of usage. We are currently working on an estimation strategy to estimate the average marginal emissions rate for nitrous oxides, sulfur dioxide, and fine particulate matter of each generator. The marginal damages of emissions from each generator can then be calculated according to the county the generator resides in (Holland et al, 2016) and then aggregated to total system damages.

power to Node 2 due to congestion caused by high wind generation for example, or low demand in Node 1, it is forced to reduce production from cheaper (relative to Node 2 coal generators) dirtier coal generators, while the downstream node is forced to switch to more expensive but cleaner gas generators, reducing the overall CO2 emissions outcomes. When congestion is not present, cheaper coal generators in Node 1 can produce more power, contributing to overall greater CO2 emissions. In this case a less economically efficient market (due to the presence of congestion) creates a public benefit by reducing CO2 emissions, while the opposite occurs when the system is economically efficient and no congestion occurs – the result is reduced public benefit as greater CO2 emissions occur.

Expanded wind generation, in any location, should be expected to lower total carbon emissions by displacing fossil fueled generators. As shown in Figure 13, when no transmission constraints exist, all scenarios reduce total carbon emissions. Diversity Scenario 3 results in the greatest total emission reductions since greater production of clean energy displaces more emissions than the other scenarios, and reduced wind generation variance implies wind is available more often to cause this effect. In the unconstrained case, Diversity Scenario 4 results in the second lowest emissions outcome because there is no constraint on the ability to export power from Node 1 to Node 2. Emissions are higher than in Scenario 3 because fewer Colorado fossil resources are displaced due to transmission increasing the cost of imported resources and at the margin affecting fewer Colorado fossil-fueled generators. Diversity Scenarios 1 and 2 result in higher emissions in the unconstrained case only because they produce less power and therefore displace less fossil generation than in the other two scenarios.

When transmission is constrained, the order of emissions outcomes changes. Diversity Scenario 4 now results in the greatest emissions because the presence of transmission constraints than the resulting greater congestion that occurs when all new wind resources are located in Wyoming reduces the potential for new wind to displace fossil-fueled generators. The other diversity Scenarios result in greater CO2 reductions primarily because they create less congestion and therefore allow more fossil resources to be displaced by zero-emission wind across the system. Across these three scenarios, the ordering of emissions reductions from greatest (Scenario 3) to least (Scenario 1) reflects the amount of wind generation created in each scenario more than the effect they have on congestion as every unit of wind power that can be used will be due to its very low marginal cost, and when wind energy is used it will displace a unit of fossil-fueled production due to the difference in marginal costs of electricity production between renewable and non-renewable generation sources.

4. Discussion

Previous studies have investigated the benefits from geographic diversification of wind, and other renewable, resources but have failed to incorporate the fact that electricity value depends on the time of day at which it is produced, and they have failed to consider how transmission congestion can undermine the benefits of spatial diversity. Furthermore, these studies have not considered both market and non-market outcomes, namely emissions reduction. Wind generation poses significant challenges to policy makers and grid operators due to the intermittency and unpredictability of the resource though it provides a low-cost, non-emissions producing alternative to conventional energy sources. In this paper we employ a scenario design of a simulated dispatch model of the Rocky Mountain Power Area (RMPA) to explore the implications of additional wind generation in a transmission-constrained grid and the potential benefits of geographic diversification. Using price, generation and transmission outcomes of the simulated models over a range of spatial configurations of wind resources we can better understand the private and social costs and benefits of using different geographic resources. We find that both the location of wind resources and the location of demand given transmission constraints are important in determining the costs and benefits to the system. Overall, where previous studies have focused on the impact spatial diversity in the selection of new wind sites can have on variation in wind generation, we demonstrate that at least for certain grid contexts, widening the scope of consideration to include consideration of time-varying electricity prices, congestion and emissions outcomes can undermine the benefits of efforts to increase spatial diversity may create.

In an unconstrained transmission system, we find results that support previous studies: greater geographic diversity of wind resources helps produce more low-cost wind generation more consistently; wind generation can be integrated into the grid with less fluctuations in power that threaten grid-reliability. We find scenarios that combine resources in both Wyoming and Colorado, rather than just one region, help achieve multiple objectives of a system operator – specifically reduced wind generation variance and lower electricity cost. Results, however, are not straightforward. We note that the benefit of greater generation potential and less variation can reduce costs, but when time of day pricing was considered, the importnance of greater production when electricity is most highly valued can potentially offset the benefit of reduced wind generation variance. It is possible that which outcome is most preferred by a system planner – greater production during high value periods at the cost of higher wind generation variance, or the opposite outcome would depend on the system planner's preferences across these two outcomes.

When transmission constraints exist and transmission congestion occurs, efforts to improve spatial diversity could exacerbate congestion outcomes by adding additional wind resources on the wrong side of transmission constraints and worsening congestion outcomes. In cases where transmission congestion is possible, it can be the case that the more important spatial location decision criteria is the avoidance of congestion over the reduction in potential wind variance. This occurs because congestion not only increases system prices in nodes downstream of any congestion, it also undermines the ability to use new wind resources located on the grid, which is the purpose of expanding renewable resources in the first place. When such resources and their generation cannot be accessed by a node blocked by transmission congestion, they also cannot help to reduce the production variation of renewable resources located in the downstream node.

Emissions outcomes are also a concern of system planners. Decisions regarding spatial location of wind generators can influence local emissions outcomes because wind will be dispatched before traditional fossil generators when possible. If such resources cause the displacement of resources further from population centers or less intense emissions sources over greater ones, overall emissions outcomes may not be improved locally. In the presence of transmission congestions such concerns can be exacerbated. Again this is an example of the fact that previous studies have usually limited the preferences of system planners to the consideration of only system reliability or minimizing generation variance above all other concerns. The realities of electricity systems and planners' preferences are more complex, and consideration of a wider scope of concerns, including system generation costs congestion and emissions outcomes greater complicates the potential benefits of spatial wind siting decisions.

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APPENDIX 2: Figures

Figure 1. Wind energy requires additional flexibility from the remaining generators. Example uses data from Minnesota 25% wind energy scenario in the WWSIS-2 study (Bird et al., 2013).

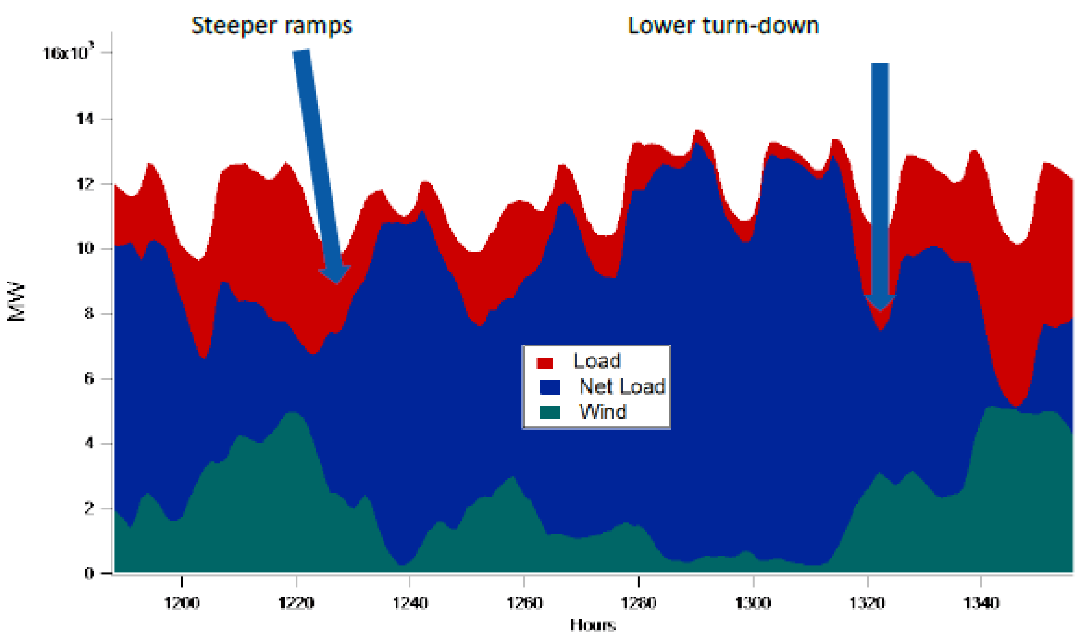


Figure 2. Map of diversity site locations.

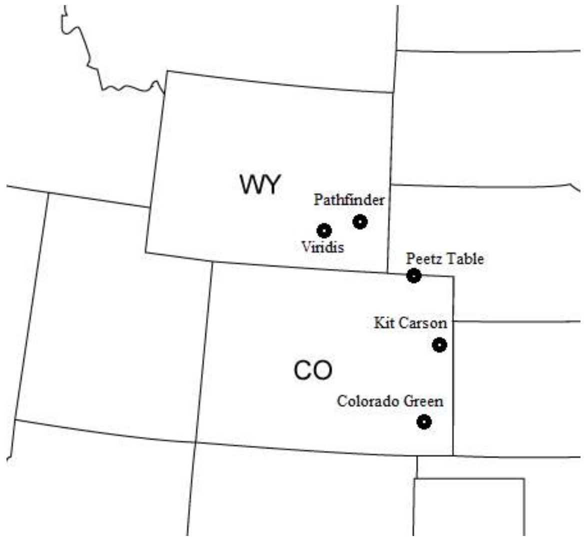


Figure 3.Diurnal pattern of capacity factors for all diversity sites, averaged across 2008 to 2012.

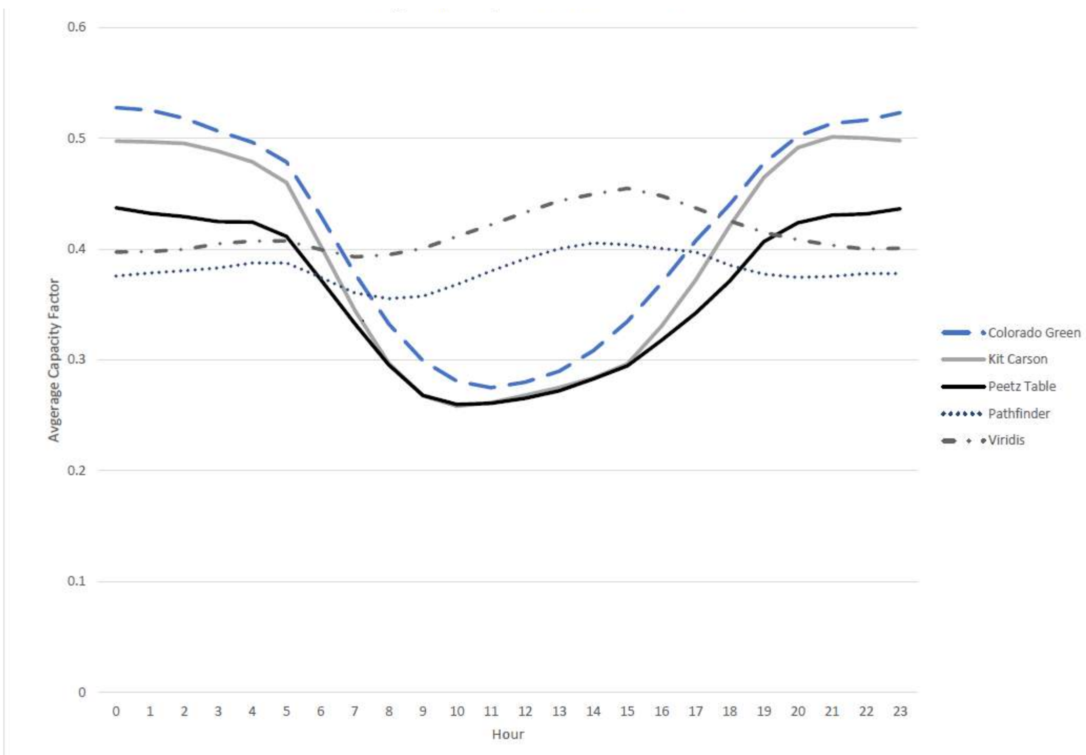


Figure 4. Diurnal averages for each diversity site in the months of Winter (December - February) across 2008 to 2012.

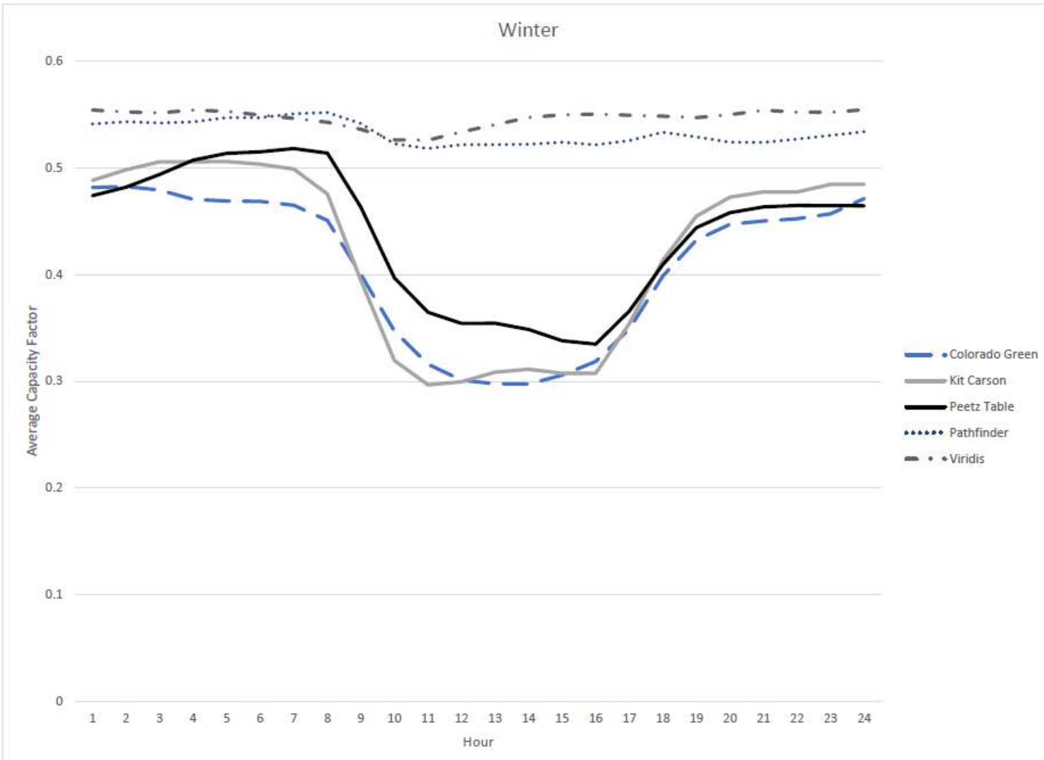


Figure 5. Diurnal averages for each diversity site in the months of Spring (March - May) across 2008 to 2012.

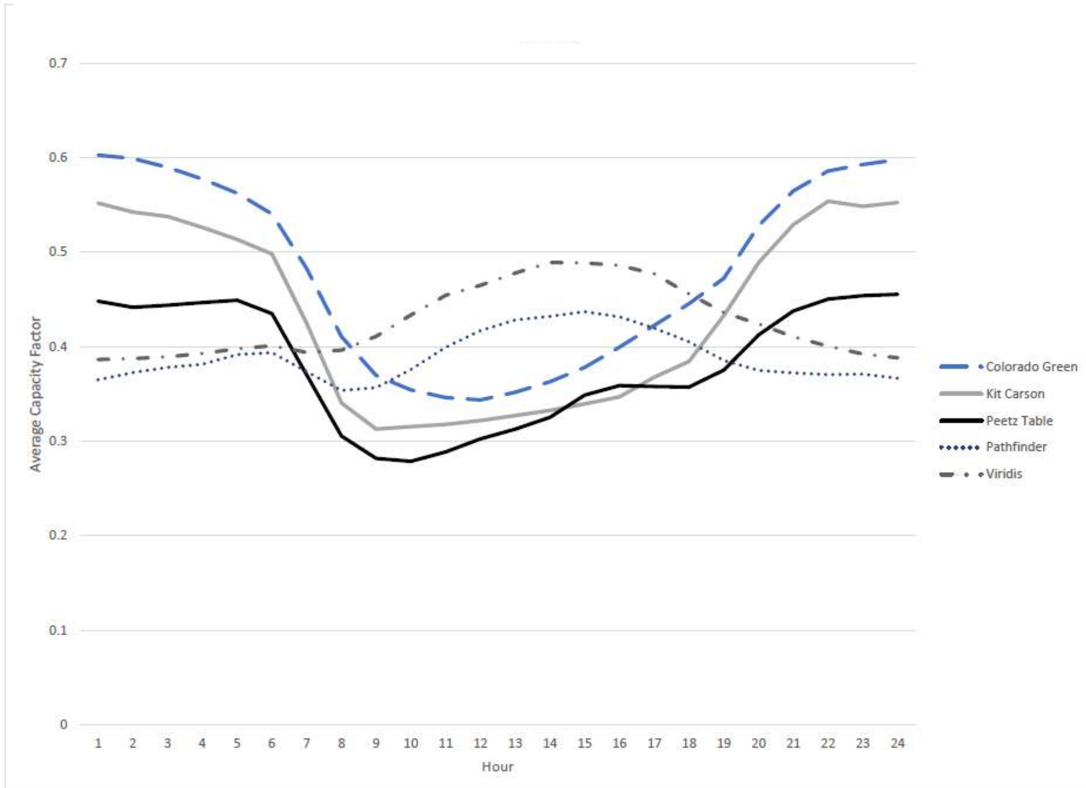


Figure 6. Diurnal averages for each diversity site in the months of Summer (June - August) across to 2008 to 2012.

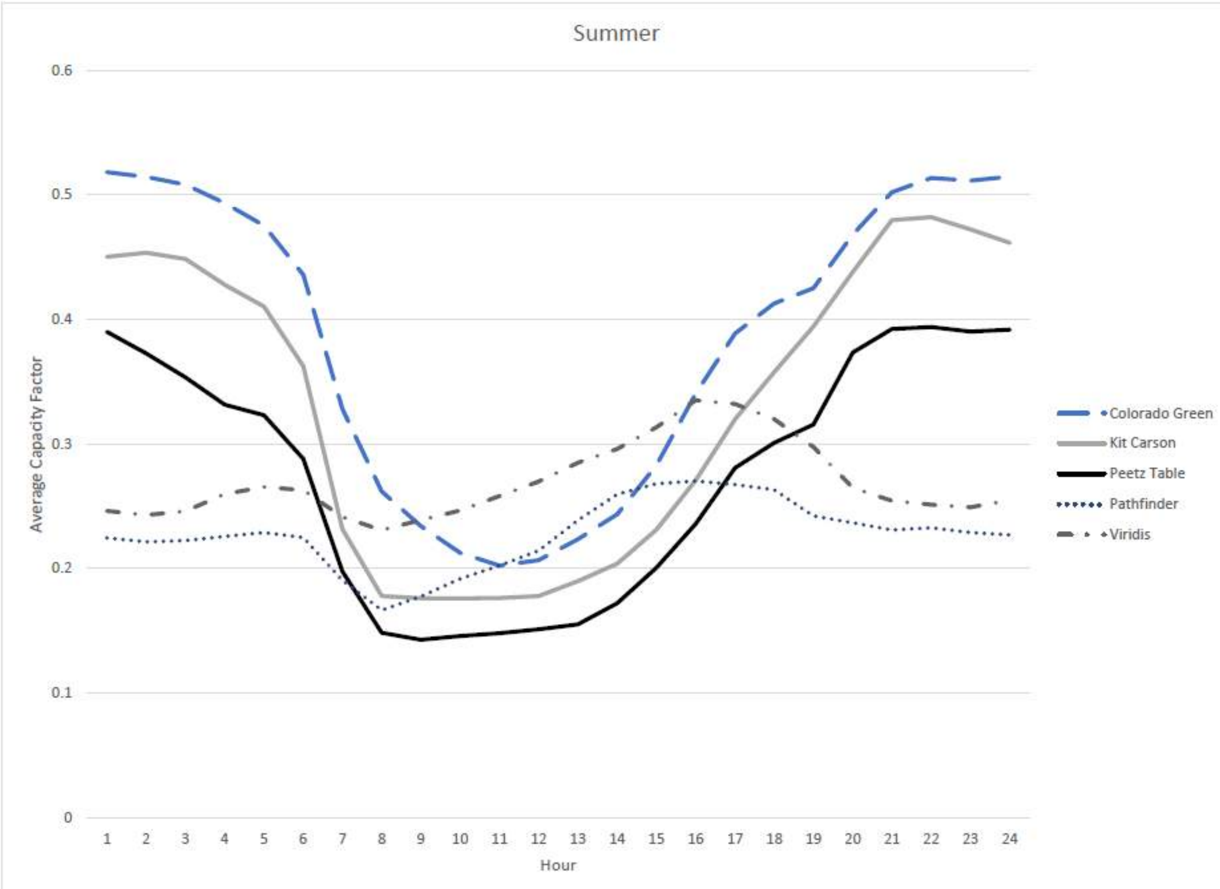


Figure 7. Diurnal averages for each diversity site in the months of Fall (September - November) across 2008 to 2012.

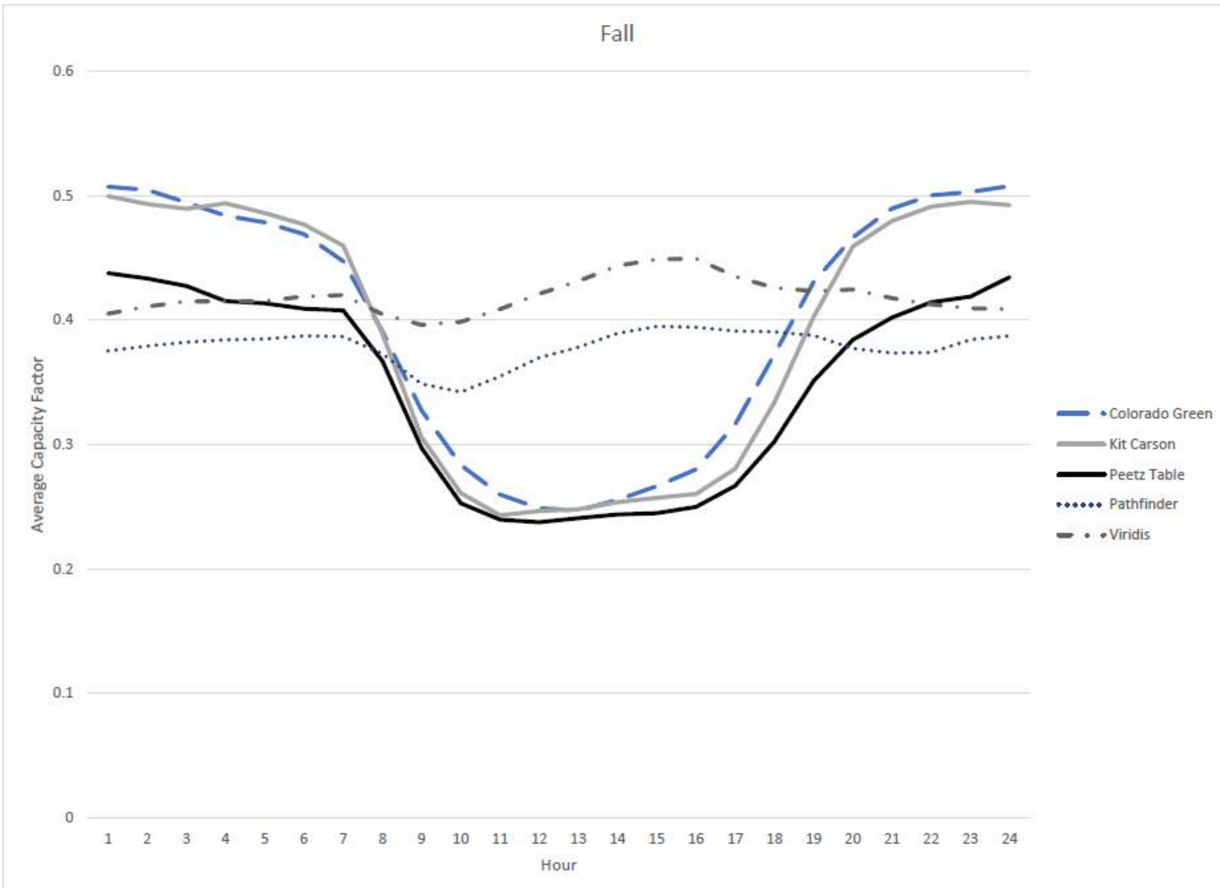


Figure 8.Simplified nodal network with simulation parameters.

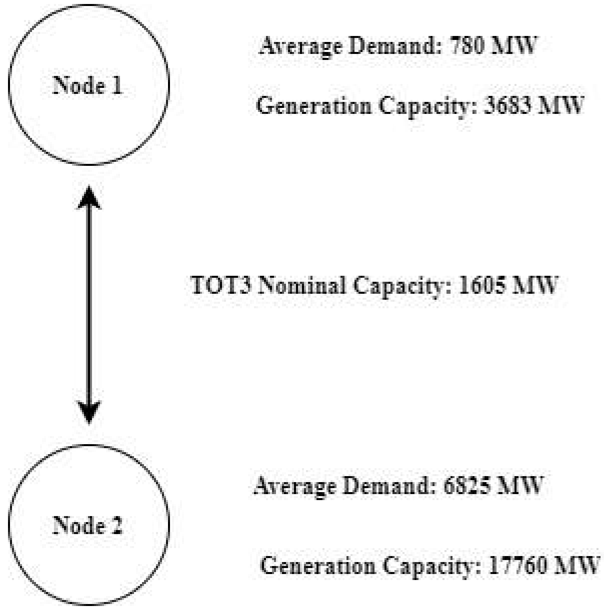


Figure 9. Monthly averages of aggregate wind power production.

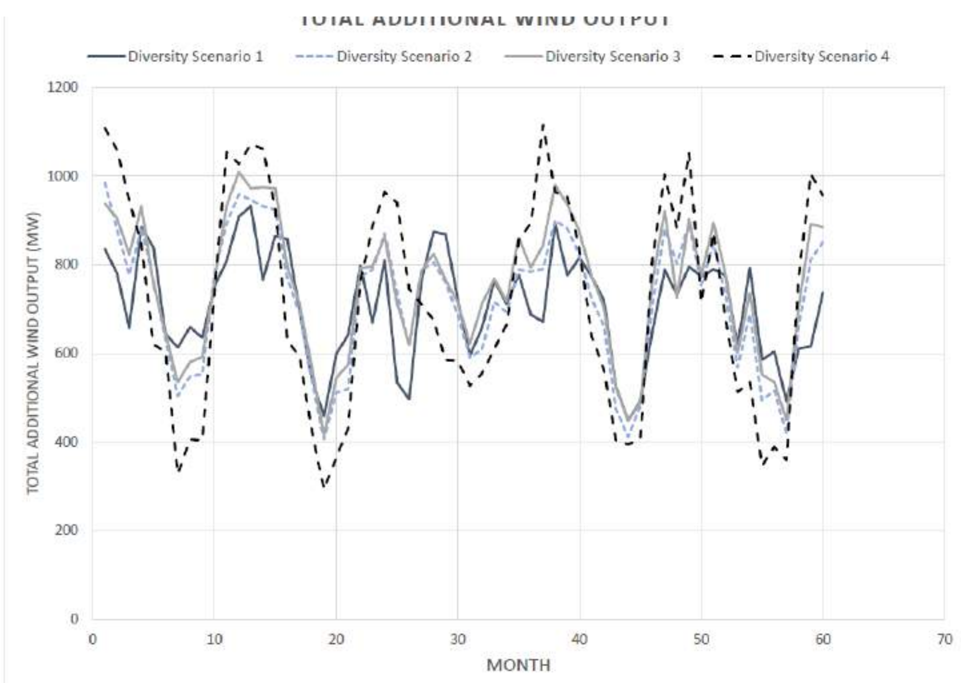


Figure 10. Average price outcomes by year for each scenario.

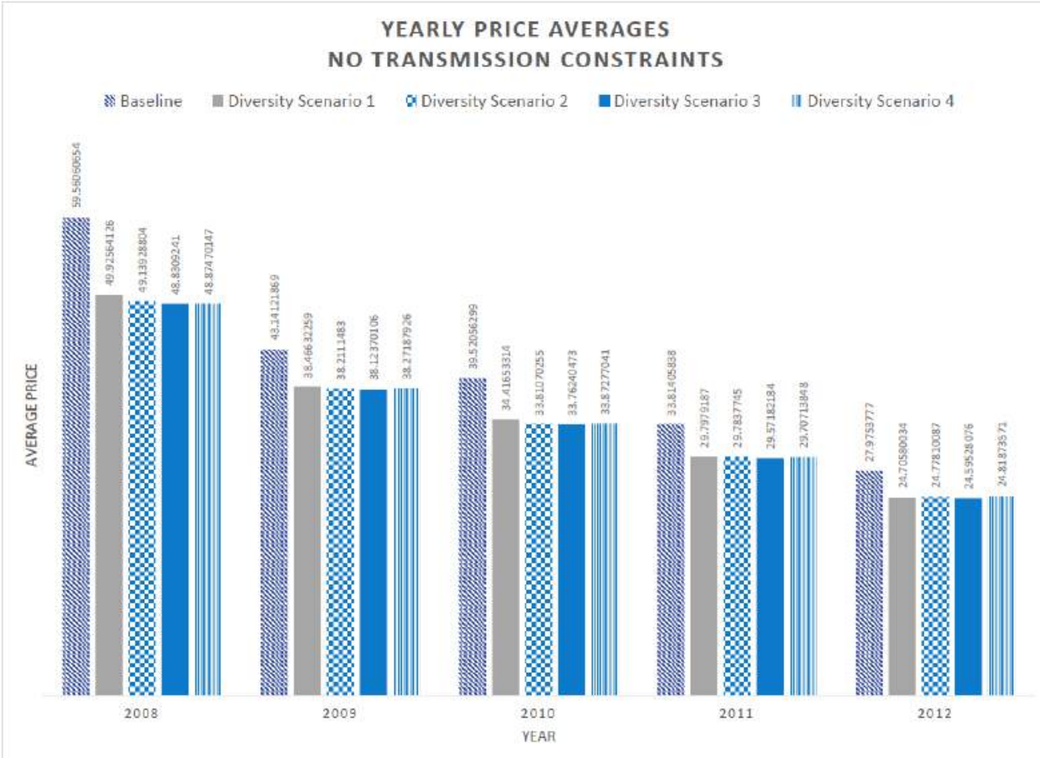
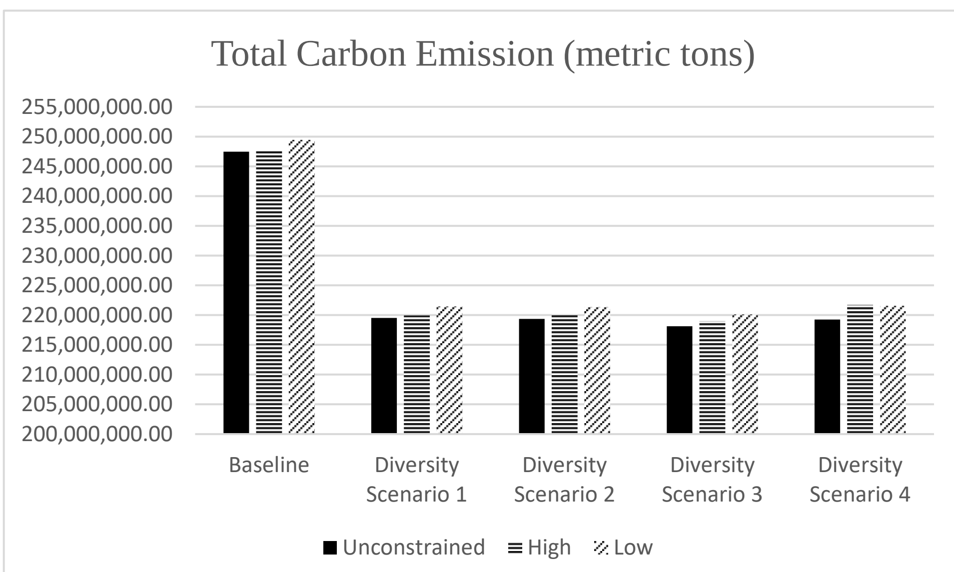


Figure 11. Average annual price differentials by scenario for High-Congestion Case

Figure 12. Annual average price differentials by scenario for Low-Congestion case

Figure 13. Total system carbon emissions for each scenario and transmission case.



APPENDIX 3: Tables

Table 1. Estimated wind farm capacities, capacity factors and summary statistics.

	Capacity (MW)	Maximum (MW)	Minimum (MW)	Average (MW)	Std. Dev. (MW)	Average Capacity Factor (%)
Wyoming						
Pathfinder	900	716.7654	0	343.3861583	249.9098101	38.15%
Viridis	900	790.0494	0	373.3666011	278.0023594	41.49%
Colorado						
Colorado Green	900	851.0406	0	375.4435241	280.2490982	41.72%
Kit Carson	300	283.6802	0	118.1561452	97.27975152	39.39%
Peetz Table	600	557.9044	0	215.6470346	184.7956712	35.94%

Table 2. Pair-wise correlation coefficients of proposed diversity sites.

	Colorado Green	Kit Carson	Peetz Table	Pathfinder	Viridis
Colorado Green	1				
Kit Carson	0.651463303	1			
Peetz Table	0.361733498	0.547986	1		
Pathfinder	0.042196941	0.111423	0.266246	1	
Viridis	0.072328655	0.092304	0.213319	0.787882	1

Table 3. Pair-wise correlation coefficients of proposed diversity sites, by season.

Winter (Dec - Feb)	Colorado Green	Kit Carson	Peetz Table	Pathfinder	Viridis
Colorado Green	1				
Kit Carson	0.5584	1			
Peetz Table	0.2431	0.5249	1		
Pathfinder	-0.0898	0.0162	0.2118	1	
Viridis	-0.0194	0.0014	0.1718	0.7332	1

Spring (Mar - May)	Colorado Green	Kit Carson	Peetz Table	Pathfinder	Viridis
Colorado Green	1	0.6978	0.4397	0.0339	0.0148
Kit Carson	0.6978	1	0.5786	0.0551	0.018
Peetz Table	0.4397	0.5786	1	0.2136	0.138
Pathfinder	0.0339	0.0551	0.2136	1	0.7988
Viridis	0.0148	0.018	0.138	0.7988	1

Summer (Jun - Aug)	Colorado Green	Kit Carson	Peetz Table	Pathfinder	Viridis
Colorado Green	1				
Kit Carson	0.6671	1			
Peetz Table	0.379	0.4789	1		
Pathfinder	0.1266	0.1387	0.1748	1	
Viridis	0.1714	0.1608	0.1508	0.6861	1

Fall (Sep - Nov)	Colorado Green	Kit Carson	Peetz Table	Pathfinder	Viridis
Colorado Green	1				
Kit Carson	0.6786	1			
Peetz Table	0.3941	0.5694	1		
Pathfinder	0.0807	0.1207	0.2404	1	
Viridis	0.1164	0.0956	0.1945	0.7963	1

Table 4. All possible combinations of simulation parameters. Note, we only run 15 of the 20 possible combinations as the No Transmission Constraints outcomes will be identical under each demand case when there is one integrated market.

	Demand Cases	
	High Congestion	**Low Congestion**
No Transmission Constraints		
	Baseline (no added wind)	Baseline (no added wind)
	Diversity Scenario 1 (1800 MW wind added)	Diversity Scenario 1 (1800 MW wind added)
	Diversity Scenario 2 (1800 MW wind added)	Diversity Scenario 2 (1800 MW wind added)
	Diversity Scenario 3 (1800 MW wind added)	Diversity Scenario 3 (1800 MW wind added)
	Diversity Scenario 4 (1800 MW wind added)	Diversity Scenario 4 (1800 MW wind added)
Transmission Constraints		
	Baseline (no added wind)	Baseline (no added wind)
	Diversity Scenario 1 (1800 MW wind added)	Diversity Scenario 1 (1800 MW wind added)
	Diversity Scenario 2 (1800 MW wind added)	Diversity Scenario 2 (1800 MW wind added)
	Diversity Scenario 3 (1800 MW wind added)	Diversity Scenario 3 (1800 MW wind added)
	Diversity Scenario 4 (1800 MW wind added)	Diversity Scenario 4 (1800 MW wind added)

Table 6. A summary of all scenarios run.

	No Transmission Constraints	Transmission Constraints - High Congestion	Transmission Constraints - Low Congestion
Baseline Scenario of actual RMPA	N/A	N/A	N/ A
Diversity Scenario 1 (CO-CO)	900 MW Colorado Green 300 MW Kit Carson 600 MW Peetz Table	900 MW Colorado Green 300 MW Kit Carson 600 MW Peetz Table	900 MW Colorado Green 300 MW Kit Carson 600 MW Peetz Table
Diversity Scenario 2(CO-WY)	900 MW Colorado Green 900 MW Pathfinder	900 MW Colorado Green 900 MW Pathfinder	900 MW Colorado Green 900 MW Pathfinder
Diversity Scenario 3 (CO-WY)	900 MW Colorado Green 900 MW Viridis	900 MW Colorado Green 900 MW Viridis	900 MW Colorado Green 900 MW Viridis
Diversity Scenario 4 (WY-WY)	900 MW Pathfinder 900 MW Viridis	900 MW Pathfinder 900 MW Viridis	900 MW Pathfinder 900 MW Viridis

Table 5. Total electricity consumption ($) by node and for the total market by scenario, under no transmission constraints.

	Total Electricity Consumption		
Scenario	**Node 1**	**Node 2**	**Total**
Baseline	$1,487,624,309	$12,544,580,752	$14,032,205,062
Diversity Scenario 1	$1,295,698,401	$10,931,493,773	$12,227,192,174
Diversity Scenario 2	$1,284,311,033	$10,830,042,246	$12,114,353,279
Diversity Scenario 3	$1,278,081,892	$10,778,148,878	$12,056,230,770
Diversity Scenario 4	$1,282,685,614	$10,810,505,214	$12,093,190,828

Table 7. Estimated capacities, capacity factors and summary statistics of each combined set of diversity sites.

	Capacity (MW)	Maximum (MW)	Minimum (MW)	Average (MW)	Std. Dev. (MW)	Capacity Factor (%)
Diversity Scenario 1 (CO-CO)	1800	1692.618	0.042264	709.2467043	463.5117323	0.394026
Diversity Scenario 2 (CO-WY)	1800	1567.605	0.62367	718.8296824	383.2820955	0.39935
Diversity Scenario 3 (CO-WY)	1800	1640.988	0.284235	748.8101249	408.7726833	0.416006
Diversity Scenario 4 (CO-WY)	1800	1506.815	0	716.7527585	499.2166033	0.398196

Table 9. Price summaries for all computed scenarios under no transmission constraints.

	Baseline Scenario	Diversity Scenario 1	Diversity Scenario 2	Diversity Scenario 3	Diversity Scenario 4
AVG 2008	59.56061	49.92564	49.13929	48.83092	48.8747
AVG 2009	43.14122	38.46632	38.21115	38.1237	38.27188
AVG 2010	39.52056	34.41653	33.8107	33.7624	33.87277
AVG 2011	33.81406	29.79792	29.78377	29.57182	29.70714
AVG 2012	27.97538	24.7058	24.7781	24.59528	24.81874
AVG 2008-2012	40.80766	35.46619	35.14824	34.98039	35.11259
STD DEV	17.41599	15.50411	14.98565	14.96121	14.97284
MAX	124.6871	123.7107	124.0414	123.5807	124.6871
MIN	13.0651	11.29217	11.29217	11.29217	11.24747
MEDIAN	31.9907	30.44577	30.43747	30.41271	30.43772

Table 8. Total electricity consumption by node and for the total market, under transmission constraints and high congestion.

	Total Electricity Consumption		
Scenario	**Node 1**	**Node 2**	**Total**
Baseline	\$1,201,441,855	\$12,963,209,684	\$14,164,651,539
Diversity Scenario 1	\$1,070,467,805	\$11,308,849,431	\$12,379,317,236
Diversity Scenario 2	\$885,404,722	\$11,669,778,641	\$12,555,183,636
Diversity Scenario 3	\$869,641,235	\$11,662,173,544	\$12,531,814,779
Diversity Scenario 4	\$749,205,341	\$12,444,149,747	\$13,193,355,088

Table 10. Total electricity consumption by node and for the total market, under transmission constraints and low congestion.

	Total Electricity Consumption		
Scenario	**Node 1**	**Node 2**	**Total**
Baseline	\$3,351,787,909	\$10,749,525,267	\$14,101,313,176
Diversity Scenario 1	\$2,924,050,556	\$9,355,164,641	\$12,279,215,197
Diversity Scenario 2	\$2,823,165,846	\$9,306,951,394	\$12,130,117,240
Diversity Scenario 3	\$2,795,382,754	\$9,269,900,532	\$12,065,283,286
Diversity Scenario 4	\$2,541,013,147	\$9,439,470,497	\$11,980,483,644

Table 11. Price summary for all computed scenarios when transmission constraints exist and there is high congestion.

Baseline Scenario	**Node 1**	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	59.2	59.57	0.38	59.56	1.59
2009	41.32	43.25	1.93	43.19	8.356
2010	25.67	41.01	15.34	39.56	66.18
2011	19.73	35.92	16.18	33.81	84.02
2012	13.16	31.15	17.99	27.98	99.51
2008-2012	**31.82**	**42.18**	**10.36**	**40.82**	**51.93**

Diversity Scenario 1 (CO-CO)	**Node 1**	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	49.67	49.93	0.27	49.93	1.55
2009	37.05	38.6	1.55	38.53	8.35
2010	23.52	35.54	12.01	34.47	65.64
2011	18.86	31.81	12.95	29.8	81.08
2012	13.12	27.92	14.8	24.72	97.06
2008-2012	**28.45**	**36.76**	**8.32**	**35.49**	**50.74**

Diversity Scenario 2 (CO-WY)	**Node 1**	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	41.34	49.91	8.27	49.14	34.47
2009	28.68	39.31	10.62	38.28	45.87
2010	19.06	37.39	18.33	33.87	85.21
2011	16.28	33.56	17.28	29.79	93.74
2012	12.09	29.44	17.35	24.79	99.62
2008-2012	**23.55**	**37.92**	**14.37**	**35.17**	**71.78**

Diversity Scenario 3 (CO-WY)	**Node 1**	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	40.67	49.79	9.12	48.83	37.14
2009	28.18	39.33	11.15	38.19	47.94
2010	18.95	37.38	18.43	33.82	85.56
2011	16.09	33.56	17.47	29.57	94.41
2012	11.95	29.44	17.49	24.61	99.65
2008-2012	**23.17**	**37.9**	**14.73**	**35.00**	**72.94**

Diversity Scenario 4 (WY-WY)	**Node 1**	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	34.79	53.47	18.68	48.87	59.47
2009	23.71	41.44	17.74	38.34	65.62
2010	16.69	40.45	23.76	33.93	90.55
2011	14.05	35.68	21.63	29.71	96.95
2012	10.91	31.15	20.24	24.83	99.89
2008-2012	**20.03**	**40.44**	**20.41**	**35.14**	**82.5**

Table 12. Price summary for all computer scenarios when transmission constraints exist and there is low congestion.

Baseline Scenario					
	Node 1	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	59.56	59.56	0	59.56	0.00%
2009	43.29	43.19	-0.1	43.19	0.40%
2010	40.32	40.42	0.09	39.56	0.20%
2011	33.62	33.84	0.22	33.81	2.00%
2012	26.74	28.13	1.4	27.98	14.00%
2008-2012	**40.71**	**41.03**	**0.32**	**40.82**	**3.00%**

Diversity Scenario 1 (CO-CO)					
	Node 1	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	49.93	49.93	0	49.93	0.00%
2009	38.64	38.53	-0.12	38.53	0.43%
2010	34.92	35.01	0.09	34.47	0.27%
2011	29.72	29.87	0.15	29.8	1.14%
2012	24.1	24.9	0.81	24.72	9.32%
2008-2012	**35.46**	**35.65**	**0.19**	**35.49**	**2.23%**

Diversity Scenario 2 (CO-WY)					
	Node 1	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	49.02	49.14	0.13	49.14	0.59%
2009	38.14	38.28	0.14	38.28	1.51%
2010	34.01	34.51	0.5	33.87	4.27%
2011	28.4	29.99	1.58	29.79	16.42%
2012	21.61	25.54	3.93	24.79	38.67%
2008-2012	**34.24**	**35.49251025**	**1.26**	**35.17**	**12.29%**

Diversity Scenario 3 (CO-WY)					
	Node 1	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	48.63	48.84	0.21	48.83	0.94%
2009	37.89	38.2	0.31	38.19	2.49%
2010	33.81	34.44	0.63	33.82	5.36%
2011	28.03	29.84	1.81	29.57	18.37%
2012	21.12	25.45	4.33	24.61	42.16%
2008-2012	**33.9**	**35.36**	**1.46**	**35.00**	**13.87%**

Diversity Scenario 4 (WY-WY)					
	Node 1	**Node 2**	**Price Differential**	**Unconstrained Transmission Price**	**% of hours of congestion per year**
Average Price					
2008	44.9	49.12	4.2	48.87	21.45%
2009	34.12	38.64	4.52	38.34	23.45%
2010	30.9	34.84	3.94	33.93	27.79%
2011	25.36	30.94	5.57	29.71	48.25%
2012	18.62	26.84	8.22	24.83	67.86%
2008-2012	**30.78**	**36.07**	**5.29**	**35.14**	**37.76%**

Appendix 5: Optimal Wind Expansion, Generation and Siting: A Theoretical Framework

Consider a social planner that oversees an electricity market system. The social planner has two main objectives, operating the electricity system at minimum cost and maintaining system reliability. System reliability ensures there are electricity generation resources available in any period to meet demand, despite unexpected spikes in demand or a sudden loss of generators. Assuming system reliability is met, the social planner will then employ least-cost electricity generation. We might think the social planner has other objectives, like reducing environmental impact of electricity generation, but for the moment we will ignore all other concerns. The social planner can expand the electricity system by adding wind generation capacity. Wind power is a low-cost source of electricity compared to other traditional dispatchable sources of electricity. Assuming the social planner can make back any fixed costs of building wind capacity, the social planner can reduce hourly electricity generation costs when wind power is generated. However, wind is an intermittent and uncertain resource, and is only valuable if it is available to meet demand. What follows is a proposed model with a cost-minimization approach to solve for the socially optimal level of wind capacity, and therefore hourly wind power generation, to minimize total costs, subject to the distribution of wind resource available. A simple analysis shows that not only fixed and variable costs of generation are important in determining wind capacity, but the expected value and variance of the wind distribution also determine the optimal level of wind capacity. The findings in this paper provide support for the importance of spatial diversification in wind siting to improve system-wide outcomes.

Model

Two key assumptions are made: (a) the social planner knows electricity demand with certainty in every period, so we can just assume it is a constant $d_t = d$, and (b) there is enough dispatchable electricity to meet demand in any hour at a reservation price, c_b, even if wind power is zero. These assumptions ensure that system reliability can always be maintained, leaving only the objective of cost-minimization. While demand is generally a stochastic variable, we make this simplifying assumption arguing that planners can predict trends in demand with relative accuracy, and if there is always enough dispatchable electricity to meet peak levels of demand, unexpected shocks would have the same effect as expected shocks.

The development of wind generation capacity, K_w, incurs an upfront fixed cost FC_w dollars per megawatt (MW) of installed capacity, however there is no marginal hourly cost of electricity generation. The social planner will build-out some level of K_w if the sum of hourly cost-savings can at least make-up the already incurred fixed costs. Wind power generation depends on the total installed wind capacity K_w and the realized wind resource (expressed as a capacity factor, the amount of wind generated per unit of capacity that would have been determined by both wind speed and technology), w. Wind is a stochastic resource that follows some probability distribution function $p(w_t)$ with an expected value μ and standard deviation σ. Wind power generation (MWh) in any period, t, is thus,

$$g_{w,t} = K_w \mathbf{E}[w_{\mathbf{t}}] \tag{1}$$

Assuming wind power is a zero-marginal cost source of electricity, it will always be used first when available, unless $w_t > d$ in any hour, where any excess wind would not be used (the marginal value of wind falls to zero). Dispatchable electricity resources, be it traditional electricity generators or electricity purchases made from outside the system, are a backstop source of electricity generation, $g_{b,t}$, and will be used to meet any net demand, $d - K_w w_t$, and zero otherwise. Assume there is a constant marginal cost, c_b, dollars per MWh at which dispatchable electricity resources are inelastic and therefore available to meet any level of net demand, even if wind generation were to fall to zero. The variable cost (taking the integral of the marginal cost c_b) of electricity generation in any period t is then,

$$\frac{c}{2}(\, d - K_w w_t)^2 \tag{2}$$

The social planner's problem is to minimize total costs, the sum of fixed costs and variable costs over the time horizon, subject to the choice of installed wind capacity and the expected level of wind as in equation (3).

$$\min_{K_w} \ \mathbf{E}[TC] = FC_w K_w + \int p(w_t) \frac{c}{2}(d - K_w w_t)^2 d_{w_t} \tag{3}$$

The first-order condition for an optimum is,

$$\frac{\partial \mathbf{E}[TC]}{\partial K_w} = FC_w - \int p(w_t) c_b (d - K_w w_t) w_t d_{w_t} = 0. \tag{4}$$

Expanding this expression, we get,

$$\frac{\partial \mathbf{E}[TC]}{\partial K_w} = FC_w - \int (p(w_t) c_b d w_t - p(w) c_b K_w w_t^2)\, d_{w_t} = 0, \tag{4}$$

and we can separate the integrals to get,

$$\frac{\partial \mathbf{E}[TC]}{\partial K_w} = FC_w - c_b d \int p(w_t) w_t \, d_{w_t} + c_b K_w \int p(w_t) w_t^2 d_{w_t} = 0. \tag{5}$$

Using the fact that $\mathbf{E}[w_t] = \int p(w_t) w_t d_{w_t}$, and $\boldsymbol{Var}[w_t] = \int p(w_t) {w_t}^2 \, d_{w_t} - \ \mathbf{E}[w_t]^2$, we can add and subtract the expression for $\mathbf{E}[w_t]^2$ to get,

$$\frac{\partial \mathbf{E}[TC]}{\partial K_w} = FC_w - c_b d \int p(w_t) w_t \, d_{w_t} + c_b K_w \int p(w_t) w_t^2 \, d_{w_t} - \mathbf{E}[w_t]^2 + \mathbf{E}[w_t]^2 = 0. \tag{6}$$

Where the first integral is $\mathbf{E}[w_t]$, which we can denote as μ, and the second integral is $\mathbf{E}[{w_t}^2] = \sigma^2 + \mu^2$ where σ^2 is the variance of w_t. Substituting these quantities gives us the following expression

$$FC_w = c_b d\mu - c_b K_w (\sigma^2 + \mu^2). \tag{7}$$

Equation (7) equates the left-hand side cost of wind capacity, with the right-hand side marginal benefit of wind capacity, that comes from the benefit of reducing electricity generation costs of the backstop technology. Manipulating equation (7) we can solve for the K_w^* optimal wind capacity that makes this equation hold and we get,

$$K_w^* = \frac{c_b d\mu - FC_w}{c_b(\sigma^2 + \mu^2)}. \tag{8}$$

Analysis

Using the expression in (8) to define $K_w^*(c_b, d, FC_w, \mu, \sigma^2)$, we analyze how the optimal level of installed wind capacity changes with respect to changes in costs and characteristics of the wind resource distribution.
Immediately we can see that as the fixed cost of wind capacity rises, that the optimal level of installed wind capacity falls as the cost of capital becomes more expensive. We also find that as the marginal cost of dispatchable generation rises, that K_w^* also rises as wind generation becomes relatively even cheaper per unit of installed megawatt of capacity. For derivation of the comparative static $\frac{\partial K_w^*}{\partial c_b}$ see the Appendix. This set of results is intuitive, as the costs change making wind generation capacity more expensive, the social planner reduces the level of installed capacity, and vice versa when the costs of wind generation fall.

We can also examine how the distribution of the wind resource impacts the socially optimal level of wind generation capacity. When the expected value of wind, μ, rises, the potential production per megawatt of installed capacity goes up. We might expect to see this increase in productivity cause K_w^* to fall, since a lower level of capacity could produce the same amount of electricity per hour or cause K_w^* to rise as each unit of capacity is now more profitable, or maybe the optimal level doesn't change. In the appendix we derive the unambiguous comparative static $\frac{\partial K_w^*}{\partial \mu} > 0$. Intuitively, a rise in μ is the same as a rise in c_b, the relative value of the wind generation to the backstop technology rises, making it more attractive thus K_w^* rises.

A less intuitive, but interesting result that falls out of the model, is how a change in the variance of the wind resource, σ^2, impacts the optimal level of wind capacity. We can easily see from equation (8) that since the variance term is in the denominator that $\frac{\partial K_w^*}{\partial \sigma^2} < 0$. This result indicates that as the variance of wind increases (holding the expected value constant) wind becomes relatively less valuable and the social planner reduces the level of installed wind capacity. Risk preferences of the social planner are not modeled in this set-up, meaning that while greater variance typically indicates greater risk making an investment decision less attractive, this isn't being directly considered. A rise in the variance term σ^2 results in a fall in the marginal benefits of wind capacity (the right-hand side of equation (7)), making each unit of wind capacity less valuable to the social planner.

Discussion

The results from this simple analysis provide some insights into what factors might influence the optimal level of wind capacity additions, namely the fixed cost of development and the marginal cost of other dispatchable electricity generation sources that are the only source of electricity in this system when no wind is added. The analysis provides support for expanding wind capacity within an electricity system to lower hourly electricity costs, if those reductions in costs are large enough to justify the initial fixed cost of installment.

Finally, our analysis of changes in the optimal level of installed wind capacity in response to changes in the distribution of wind resource indicates that tighter distributions of wind resource are favorable. An important tool to influence the expected value and the variance of the wind resource available is wind siting of turbines. The variance term σ^2 for any given capacity level K_w could be lowered, and in some cases the mean μ could be simultaneously increased, by taking advantage of spatial diversification in wind sites. In other words, by thoughtfully siting individual wind turbines in a specific spatial configuration, that combined make up K_w capacity, the overall distribution of the wind resource can be manipulated. The analysis here suggests that wind siting and geographic diversification of wind resources can be a tool to encourage more installed wind capacity.

APPENDIX: Comparative Statics

The optimal level of installed wind capacity, K_w^*, can be defined by the following expression,

$$K_w^* = \frac{c_b d\mu - FC_w}{c_b(\sigma^2 + \mu^2)}.$$

We know that the optimal K_w^* depends on the fixed cost of developing wind capacity, the marginal cost of generating dispatchable electricity, and on the expected value and variance of the wind resource w_t. Using comparative statics, we can analyze how individual variable changes, *ceteris paribus,* impact the optimal level of installed wind capacity.

We can immediately see from the equation for K_w^* that as fixed costs of installing wind capacity, FC_w, rise, all else equal, that the level of installed wind capacity will fall as we would intuitively expect, $\frac{\partial K_w^*}{\partial FC_w}$. As the fixed cost of developing wind generation rise, the social planner is faced with a higher cost of build-out and would therefore reduce the amount of wind capacity.

It is not immediately obvious how the optimal level of wind capacity will respond to an increase in the hourly generation cost of dispatchable electricity. We can solve for the comparative static as follows,

$$\frac{\partial K_w^*}{\partial c_b} = \frac{c_b(\sigma^2 + \mu^2)d\mu - (c_b d_t - FC_w)(\sigma^2 + \mu^2)}{[c_b(\sigma^2 + \mu^2)]^2},$$

which can be simplified and written as,

$$\frac{\partial K_w^*}{\partial c_b} = \frac{(FC_w)(\sigma^2 + \mu^2)}{[c_b(\sigma^2 + \mu^2)]^2} > 0.$$

Thus, we find that as the marginal cost of electricity generation from other dispatchable resources rises, wind generation capacity also rises. Again, this makes intuitive sense, as other sources of electricity generation become more expensive, the zero-marginal cost wind energy becomes that much more attractive and it becomes that much easier to make back the fixed costs of building the wind capacity.

We might also consider how changes in the expected value and variance of the wind resource might change the optimal level of wind capacity installments. We can solve the comparative static with respect to the expected value of wind, μ,

$$\begin{aligned}\frac{\partial K_w^*}{\partial \mu} &= \frac{c_b(\sigma^2+\mu^2)c_b d - (c_b d\mu - FC_w)(c_b\mu)}{[c(\sigma^2+\mu^2)]^2} \\ &= \frac{c_b^2\sigma^2 d + c_b^2 d\mu^2 - c_b^2 d\mu^2 + c\mu FC_w}{[c(\sigma^2+\mu^2)]^2} \\ &= \frac{c_b^2\sigma^2 d + c\mu FC_w}{[c(\sigma^2+\mu^2)]^2} > 0.\end{aligned}$$

As the expected value of w_t rises, we see that the optimal level of wind capacity also rises. With higher expected values of w_t, we expect to offset more dispatchable electricity generation, therefore reducing hourly expected electricity costs even further, making it easier to offset more of the fixed cost of wind capacity and making wind a more attractive investment.

Finally, we can easily see that $\frac{\partial K_w^*}{\partial \sigma^2} < 0$ just from the expression that defines the optimal level of wind capacity. As the variance of the wind resource, σ^2, rises, the optimal level of wind capacity falls. It is not intuitively clear why this is necessarily the case. One argument might be that, as the variance of wind increases, the tails of the pdf become thicker, and it is more likely that either the realized wind resource is very low and not particularly valuable, or too high (above demand?) and the marginal value decreases.